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COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	)	
A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

SECTION II

FILING REQUIREMENTS

VOLUME 1 OF 5

December 23, 2014

Filing Requirement
KRS 278.180

Filing Requirement:

Changes in rates, how made.

(1) ***Except as provided in subsection (2) of this section, no change shall be made by any utility in any rate except upon thirty (30) days' notice to the commission, stating plainly the changes proposed to be made and the time when the changed rates will go into effect. However, the commission may, in its discretion, based upon a showing of good cause in any case, shorten the notice period from thirty (30) days to a period of not less than twenty (20) days. The commission may order a rate change only after giving an identical notice to the utility. The commission may order the utility to give notice of its proposed rate increase to that utility's customers in the manner set forth in its regulations.***

(2) ***The commission, upon application of any utility, may prescribe a less time within which a reduction of rates may be made.***

Response:

The Company has complied with KRS 278.180.

Filing Requirement
KRS 278.2205 (6)

Filing Requirement:

The CAM shall be filed as part of the initial filing requirement in a proceeding involving an application for an adjustment in rates pursuant to KRS 278.190.

Response:

Please see the attached Cost Allocation Manual.

AEP AMERICAN ELECTRIC POWER

COST ALLOCATION MANUAL

As Of June 30, 2014

Corporate Accounting

The manual has been written to document AEP's approach to cost allocation and transfer pricing of affiliate transactions. Its purposes are to

- provide an easily referenced source of information
- state and clarify policy
- formalize procedures
- provide a basis of communication between all employees concerning cost allocation matters
- meet all regulatory requirements for maintaining a cost allocation manual.

The contents of the manual have been approved by management. Responsibility for adhering to the policies and procedures rests with every employee.

The manual is maintained in the A-Z index of AEP Now, under 'Cost Allocation Manual'. Maintenance of the documents incorporated in the manual by reference is the responsibility of the individuals and groups designated in the manual.

Errors in content and other requests for revision of this manual should be directed to the attention of Kathy L. Messer/Donald W. Roberts.

Rhoderick C. Griffin
Manager – Regulated Accounting

F. Scott Travis
Assistant Controller – Regulated Accounting
Utility General and Regulatory Accounting

AEP AMERICAN ELECTRIC POWER

CAM
Amendment Record

Rev. No.	Date Issued	Rev. No.	Date Issued	Rev. No.	Date Issued	Rev. No.	Date Issued
1	01-02-01	26	03-15-13	51		76	
2	10-22-01	27	08-31-13	52		77	
3	05-10-02	28	03-27-14	53		78	
4	10-18-02	29	09-15-14	54		79	
5	05-05-03	30		55		80	
6	08-29-03	31		56		81	
7	03-10-04	32		57		82	
8	08-27-04	33		58		83	
9	03-10-05	34		59		84	
10	08-30-05	35		60		85	
11	03-15-06	36		61		86	
12	08-31-06	37		62		87	
13	03-16-07	38		63		88	
14	09-24-07	39		64		89	
15	04-15-08	40		65		90	
16	09-25-08	41		66		91	
17	03-31-09	42		67		92	
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AMERICAN ELECTRIC POWER

Document Number 00-00-01

Cost Allocation Manual

Section

Controls

Subject

TABLE OF CONTENTS

This table of contents is intended to give a cover-to-cover overview of the contents and organization of the AEP Cost Allocation Manual (CAM). See HOW TO USE THIS MANUAL (00-00-02) for an explanation of the numbering system.

AMERICAN ELECTRIC POWER

Document Number **00-00-01**

Cost Allocation Manual

Section

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AEP AMERICAN ELECTRIC POWER

Document Number **00-00-02**

Cost Allocation Manual

Section

Controls

Subject

HOW TO USE THIS MANUAL

SUMMARY	This Manual is divided into
	TABS - major divisions within the manual
	SECTIONS - divisions within a TAB
	SUBJECTS - divisions within a SECTION.
DOCUMENT NUMBERING SYSTEM	Each document (i.e., subject) has a unique 6-digit number. This number is divided into 3 sets of two digits which are separated by dashes.
	EXAMPLE: **05 – 03 – 02** TAB-SECTION-SUBJECT
INDEXES	The alphabetic subject index is the key to this manual. It appears in the “Controls” TAB following this document.
Alphabetic Subject	The alphabetic subject index (00-00-03) lists every subject in this manual in alphabetical order along with the document number at which each subject may be located. To be able to retrieve information, each subject (and important captions within a subject) are listed three or more ways in the index.
Locating a Document	Document numbers appear in bold print on the upper right corner of each page (see top of this page). To locate a Subject:
	1. Refer to the Alphabetic Subject Index and locate the SUBJECT you need.
	2. Note the Document Number indicated
	EXAMPLE: **05-03-02**

INDEXES (Cont'd)

Locating a Document (Cont'd)

3. Locate TAB 5 of the manual and within this TAB find SECTION 03 and SUBJECT 02. Or, if you are viewing this manual electronically using Acrobat Reader, simply click on the subject line listed in the table of contents.

TABLE OF CONTENTS

The table of contents (00-00-01) is intended to give a cover-to-cover overview of the manual contents and organization. It lists contents of a TAB to the SUBJECT level in document number order. (Subjects are listed alphabetically in the Alphabetic Subject Index).

FORMAT

The format followed for each TAB within this manual may vary. Uniformity of format has been attempted to the extent practicable.

DISTRIBUTION

The AEPSC Corporate Accounting Department is solely responsible for the issuance, revision and distribution of all copies of this manual and database.

Revisions or additions to the manual will be issued as required. If practical, such revisions and/or additions will be accumulated and issued periodically as a group. The date of the latest revision or addition will appear at the bottom of the page in the left-hand corner.

AMENDMENTS

All users of this manual are urged to contribute ideas and suggestions for revisions to this manual.

Amendment Record

An amendment record is kept of all revisions to this manual. The amendment record appears in the front of this manual as the first document in the "Controls" SECTION.

Cost Allocation Manual

Section

Controls

Subject

ALPHABETIC SUBJECT INDEX

This subject index lists every subject included in this manual in alphabetical order. The location document number is given for each subject. To aid retrievability, subjects are listed in two or more different ways.

AEP AMERICAN ELECTRIC POWER

Document Number 00-00-03

Cost Allocation Manual

Section

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Subject

ALPHABETIC SUBJECT INDEX

C (Con't)

AEP AMERICAN ELECTRIC POWER

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O

P

AMERICAN ELECTRIC POWER

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AEP AMERICAN ELECTRIC POWER

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Cost Allocation Manual

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ALPHABETIC SUBJECT INDEX

S (Con't)

T

V

W

AEP AMERICAN ELECTRIC POWER

Document Number **01-01-01**

Cost Allocation Manual

Section

Introduction

Subject

OVERVIEW (GENERAL)

SUMMARY	American Electric Power Company, Inc. (AEP) is a public utility holding company. It has subsidiaries that conduct regulated operations and non-regulated operations.
BUSINESS	AEP is one of the United States' largest generators of electricity and owns the nation's largest electricity transmission system. AEP delivers electricity to customers in eleven states: Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. Wholly-owned subsidiaries are involved in power engineering and construction services and energy management.
ORGANIZATION CHART	The ownership relationship between AEP, its subsidiaries, and their subsidiaries at successive levels is captured in AEP's corporate chart.
AFFILIATE TRANSACTIONS	AEP, its subsidiaries and certain other affiliates in the AEP holding company system conduct capital (i.e., financial) transactions among themselves. The subsidiaries, in certain situations, also perform services for one another.

AMERICAN ELECTRIC POWER

Document Number **01-02-01**

Cost Allocation Manual

Section

Organization Chart

Subject

OVERVIEW

SUMMARY

American Electric Power Company, Inc. (AEP) is a public utility holding company. It has direct subsidiaries (first tier) and indirect subsidiaries (second tier and lower).

CORPORATE CHART

A listing of the direct and indirect subsidiaries of AEP, including domestic and foreign subsidiaries, is contained in AEP's corporate organization chart.

SUMMARY

American Electric Power Company, Inc. (AEP) is a public utility holding company. It has no customers or employees nor does it own any utility property. AEP does own common stock of nine operating electric utility companies and the common stock of AEP Utilities, Inc, which in turn owns common stock of two operating electric utility companies.

AEP also owns common stock of American Electric Power Service Corporation (AEPSC) and other domestic and foreign subsidiaries.

AEPSC is a management, professional and technical services organization that provides such services, at cost, to AEP, the operating electric utility companies in the AEP System, and other affiliated companies. Other AEP subsidiaries provide power engineering, energy consulting and energy management services.

CORPORATE ORGANIZATION CHART

The following organization chart lists hierarchically all of the direct and indirect subsidiaries of AEP. Company names are indented to identify them as subsidiaries of the company that is listed immediately above them at the next tier. Some companies are subsidiaries of more than one company. The footnotes provide a general description of the business conducted by each company.

00. American Electric Power Company, Inc. [Note A]
01. AEP Coal, Inc. [Note L]
02. AEP Kentucky Coal, LLC [Note L]
02. Snowcap Coal Company, Inc. [Note L]
01. AEP Credit, Inc. [Note R]
01. AEP Energy Supply LLC [Note N]
02. AEP C&I Company, LLC [Note W]
03. AEP Retail Energy Partners LLC [Note I]
04. BlueStar Energy Holdings, Inc. [Note I]
05. AEP Energy, Inc. [Note I]

05. BSE Solutions LLC [Note I]
06. BlueStar Energy S.A.C. [Note I]
05. BlueStar Energy S.A.C. [Note I]
03. AEP Texas Commercial & Industrial Retail GP, LLC [Note W]
04. AEP Texas Commercial & Industrial Retail Limited Partnership [Note W]
03. AEP Texas Commercial & Industrial Retail Limited Partnership [Note W]
03. REP Holdco, LLC [Note W]
04. Mutual Energy SWEPCO, LP [Note W]
04. REP General Partner, LLC [Note W]
05. Mutual Energy SWEPCO, LP [Note W]
02. AEP Energy Partners, Inc. [Note W]
02. AEP Generation Resources Inc. [Note E]
03. Cardinal Operating Company [Note E]
03. Central Coal Company (Inactive) [Note K]
03. Conesville Coal Preparation Company [Note M]
03. Ohio Franklin Realty, LLC [Note T]
01. AEP Fiber Venture, LLC [Note C]
02. AFN, LLC [Note C]
01. AEP Generating Company [Note E]
01. AEP Investments, Inc. [Note F]
02. Braemar Energy Ventures III, LP [Note DD]
02. Columbus Collaboratory LLC [Note DD]
02. First Hydrogen, Inc [Note DD]
02. GridgEdge Networks, Inc. [Note DD]
02. Microcell Corporation [Note DD]
02. Powerspan Corp [Note DD]
02. Universal Supercapacitors, LLC [Note DD]
01. AEP Nonutility Funding LLC [Note AA]
01. AEP Pro Serv, Inc. [Note I]
02. United Sciences Testing, Inc. [Note B]
01. AEP Resources, Inc. [Note H]
02. AEP Energy Services, Inc. [Note D]
03. AEP Energy Services Gas Holding Company [Note C]
02. AEP River Operations LLC [Note Y]
03. AEP Elmwood LLC [Note Y]
04. Conlease, Inc. [Note Y]
04. International Marine Terminals Partnership [Note Y]
05. IMT Land Corp [Note T]
03. MarineNet, LLC [Note Y]
01. AEP T&D Services, LLC [Note BB]
01. AEP Transmission Holding Company, LLC [Note P]

02. AEP Transmission Company, LLC [Note P]
03. AEP Appalachian Transmission Company, Inc. [Note P]
03. AEP Indiana Michigan Transmission Company Inc. [Note P]
03. AEP Kentucky Transmission Company, Inc. [Note P]
03. AEP Ohio Transmission Company Inc. [Note P]
03. AEP Oklahoma Transmission Company, Inc. [Note P]
03. AEP Southwestern Transmission Company, Inc. [Note P]
03. AEP West Virginia Transmission Company, Inc. [Note P]
02. AEP Transmission Partner LLC [Note P]
03. Electric Transmission America, LLC [Note P]
04. Prairie Wind Transmission, LLC [Note P]
03. Electric Transmission Texas, LLC [Note P]
02. Electric Transmission America, LLC [Note P]
03. Prairie Wind Transmission, LLC [Note P]
02. Electric Transmission Texas, LLC [Note P]
02. PATH West Virginia Series [Note P]
03. PATH West Virginia Transmission Company, LLC [Note P]
04. PATH - WV Land Acquisition Company, LLC [Note T]
02. Pioneer Transmission, LLC [Note P]
02. Potomac-Appalachian Transmission Highline, LLC [Note J]
02. RITELine Indiana, LLC [Note P]
02. RITELine Transmission Development, LLC [Note P]
03. RITELine Illinois, LLC [Note P]
03. RITELine Indiana, LLC [Note P]
02. Transource Energy, LLC [Note P]
03. Transource Missouri, LLC [Note P]
01. AEP Utilities, Inc. [Note O]
02. AEP Texas Central Company [Note J]
03. AEP Texas Central Transition Funding II LLC [Note AA]
03. AEP Texas Central Transition Funding III LLC [Note AA]
03. AEP Texas Central Transition Funding LLC [Note AA]
02. AEP Texas North Company [Note J]
03. AEP Texas North Generation Company, LLC [Note E]
02. CSW Energy Services, Inc. [Note I]
03. Nuvest, LLC [Note U]
04. ESG Manufacturing, LLC [Note U]
02. CSW Energy, Inc. [Note S]
03. AEP Desert Sky GP, LLC [Note X]
04. Desert Sky Wind Farm LP [Note X]
03. AEP Desert Sky LP II, LLC [Note X]
04. Desert Sky Wind Farm LP [Note X]

03. AEP Wind Holding, LLC [Note X]
04. AEP Properties, LLC [Note X]
04. AEP Wind GP, LLC [Note X]
05. Trent Wind Farm, LP [Note X]
04. AEP Wind LP II, LLC [Note X]
05. Trent Wind Farm, LP [Note X]
01. AEP Utility Funding, LLC [Note O]
01. American Electric Power Service Corporation [Note B]
02. American Electric Power Foundation [Note FF]
01. Appalachian Power Company [Note J]
02. Appalachian Consumer Rate Relief Funding LLC [Note AA]
02. Cedar Coal Co. (Inactive) [Note K]
02. Central Appalachian Coal Company (Inactive) [Note K]
02. Central Coal Company (Inactive) [Note K]
02. Southern Appalachian Coal Company (Inactive) [Note K]
01. Franklin Real Estate Company [Note T]
02. Indiana Franklin Realty, Inc. [Note T]
01. Indiana Michigan Power Company [Note J]
02. Blackhawk Coal Company (Inactive) [Note J]
02. Price River Coal Company, Inc. (Inactive) [Note J]
01. Kentucky Power Company [Note J]
01. Kingsport Power Company [Note J]
01. Ohio Power Company [Note J]
02. Ohio Phase-In-Recovery Funding LLC [Note AA]
02. Ohio Valley Electric Corporation [Note E]
03. Indiana-Kentucky Electric Corporation [Note E]
01. Ohio Valley Electric Corporation [Note E]
02. Indiana-Kentucky Electric Corporation [Note E]
01. PowerTree Carbon Company, LLC [Note D]
01. Public Service Company of Oklahoma [Note J]
01. Southwestern Electric Power Company [Note J]
02. Arkansas Coalition for Affordable and Reliable Electricity, LLC [ACARE] [Note F]
02. Dolet Hills Lignite Company, LLC [Note L]
02. Oxbow Lignite Company, LLC [Note L]
02. Southwest Arkansas Utilities Corporation [Note T]
02. The Arklahoma Corporation [Note P]
01. Wheeling Power Company [Note J]

Notes:
A. Public utility holding company.
B. Management, professional and technical services.
C. Telecommunications.
D. Broker and market energy commodities.
E. Generation.
F. Investor in companies developing energy-related ideas, products and technologies.
G. Distributed generation products.
H. International energy-related investments, trading and other projects.
I. Non-regulated energy-related services and products.
J. Domestic electric utility.
K. Mining (inactive).
L. Mining (active).
M. Coal preparation.
N. Inactive.
O. Subsidiary public utility holding company.
P. Electric transmission.
Q. Leasing.
R. Accounts receivable factoring.
S. Independent power.
T. Real estate.
U. Staff augmentation to power plants.
V. Retail energy sales.
W. Marketing of natural gas, electricity or energy-related products.
X. Wind Power Generation.
Y. Barging Services
AA. Finance Subsidiary
BB. Energy services including operations, supply chain, transmission and distribution
CC. Gas pipeline and processing
DD. Domestic energy-related investments, trading and other projects
EE. Trust

FF. Nonprofit
GG Variable Interest Entity (VIE) * See Footnote below

Variable Interest Entity (VIE) in accordance with generally accepted accounting principles, no costs are allocated to this entity.

AEP AMERICAN ELECTRIC POWER

Document Number **01-03-01**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

OVERVIEW

SUMMARY	The electric utilities in the AEP holding company system conduct transactions with each other, American Electric Power Service Corporation (AEPSC) and their non-regulated affiliates.
AEPSC Services Rendered	AEPSC provides management, technical and professional services to other companies within the AEP holding company system.
	01-03-02
INTERCOMPANY PRODUCTS AND SERVICES	The electric utility companies provide products and services to each other and in certain cases they provide products and services to non-regulated affiliates and receive products and services from non-regulated affiliates.
	01-03-03
MONEY POOL	The operation of the AEP Utility and Non-utility Money Pool is designed to match, on a daily basis, the available cash and borrowing requirements of its participants, thus minimizing the need to borrow from external sources.
	01-03-04
RESEARCH AND DEVELOPMENT	Research and development (R&D) activities are generally performed by AEP System companies on a shared basis. AEPSC manages most R&D projects.
	01-03-05

AEP AMERICAN ELECTRIC POWER

Document Number **01-03-01**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

OVERVIEW

FINANCIAL TRANSACTIONS

The AEP System companies, although legally separated, operate on an integrated basis, as permitted by law and regulation. Financial transactions are conducted on a regular basis in support of the integrated activities.

01—03-06

INTELLECTUAL PROPERTY

Revenues derived from non-associates for the resale and licensing of property protected by copyright, patent or trademark laws are shared among AEP affiliates and regulated by the Federal Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005.

01-03-07

CONVENIENCE PAYMENTS

Payments made for the convenience of another associate company within the AEP System need to be kept to a minimum and be reimbursed immediately to the paying company.

01-03-08

SUMMARY

The services provided by AEPSC are regulated by the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005.

SUMMARY OF AEPSC SERVICES

The following table provides a listing of services AEPSC provides to affiliate companies:

GROUP/FUNCTION	DESCRIPTION
Audit Services	Internal audit services related to operational, financial, contract, customer accounting, information technology, stores, and other business functions.
Business Logistics	Travel, land, facilities, fleet, equipment management, general procurement and other support services.
Chairman	Services provided by the office of the chairman.
Commercial Operations	Capture maximum value for surplus generation and secure competitive, low-cost supplies from the market to meet the needs of the AEP System. Operational analyses, responsible for decision support modeling, dispatch pricing, and position reporting. Manage and administer non-

GROUP/FUNCTION	DESCRIPTION
	affiliated gas marketing.
Corporate Accounting	Specialized accounting, tax and other financial services related to corporate development. Tax research, consultation and compliance at local, state and federal levels.
Corporate Communications	Corporate communications externally to customers, shareholders and the public, and internally to employees.
Corporate Human Resources	Administration and coordination of employee benefit plans, payroll processing, employee records, labor relations, certain employee & management training, centralized processing of medical benefit claims, and human resource management.
Corporate Planning and Budgeting	Strategic planning and economic analysis of capital budgeting and operational decisions.
Customer and Distribution Services	Mapping services, project management,

GROUP/FUNCTION	DESCRIPTION
	design and development of construction projects, drafting and engineering services, contract administration, forestry, and planning services.
Electric Transmission Texas	Includes, among other items, management support of all areas of Texas Transmission.
Environment and Safety	Support of environmental and safety concerns.
Federal Affairs	Monitors and participates in rulemakings and other public policy discussions at various federal agencies.
Finance, Accounting and Strategic Planning Administration	Support of system wide budgeting and reporting tools, financial and resource planning, regulatory and rate analysis, tracking and monitoring of construction/capital investments.
Fossil and Hydro Generation	Provide power plants with engineering and technical resources necessary to manage day-to-day operations issues affecting unit

GROUP/FUNCTION	DESCRIPTION
	reliability, availability, and equipment performance.
Regulated Commercial Operations	Manage fuel procurement and related transportation and handling activities.
Generation Administration	Services provided by the Generation Administration.
Generation Business Services	Business support services for operation and maintenance of AEP generating assets.
Generation Engineering and Technical Services – Engineering Project Field Services	Administration of all generation assets: fossil, hydro, and engineering technical & environmental services
Information Technology	Information processing, business unit support, application development, client computing and technical software support and EAS solutions and telecommunication operations.
Legal General Counsel Administration	Legal counsel and public/regulatory policy for questions, issues, cases, etc. for all aspects of the AEP System.

GROUP/FUNCTION	DESCRIPTION
Nuclear Generation	Administration of all nuclear generation assets.
Regulatory Services	Support of system wide regulatory and rate analysis.
Risk and Strategic Initiatives	Coordination of risk assessment, credit risk management and insurance coverage.
Transmission Administration	Services provided by Transmission Administration.
Transmission Engineering and Project Services	Coordinates engineering and design of all transmission line and project stations and coordinates activities required for the successful installation of transmission line and transmission/distribution station facilities.
Transmission Joint Venture Projects	Responsible for the management support of all areas of Transmission Joint Venture projects.
Transmission Projects	Responsible for the management support of all areas of Transmission projects.
Transmission	Responsible for the

GROUP/FUNCTION	DESCRIPTION
Reliability Compliance	safe, reliable, and cost effective operation of AEP's transmission assets.
Transmission Strategy and Business Development	Responsible for developing and executing transmission strategy and business plans in alignment with AEP's corporate strategy.
Transmission System and Region Operations	Responsible for the operation of AEP's transmission Operations.
Treasury and Investor Relations	Cash management, financing, and investment services.
Utility Operations Business Services	Distribution operations, customer and regulatory relationships.
Utility Operations East	Distribution operations, customer and regulatory relationships.
Utility Operations West	Distribution operations, customer and regulatory relationships.

SUMMARY

The non-tariffed products and services provided by AEP's regulated utilities to affiliate companies and vice versa are governed by written agreements between and among the companies (see TAB **04** in this manual). The following tables describe the nature of the various transactions that are conducted with affiliates in three categories:

- products and services provided by regulated utilities to non-regulated affiliates
- products and services provided to regulated utilities by non-regulated affiliates
- products and services provided by regulated utilities to each other.

PRODUCTS AND SERVICES PROVIDED BY REGULATED UTILITIES TO NON-REGULATED AFFILIATES

The following table describes the nature of products and services provided by the AEP System's regulated utilities to non-regulated affiliates:

CATEGORY	***DESCRIPTION***
Facilities Management	Construct, operate and maintain equipment, approval of outside contracts & monitoring work of contractors.
Pole Attachments	Lease poles and towers for communication and other purposes.
Customer Accounting	Service, administer, and collect receivables sold to AEP Credit, Inc.

CATEGORY	***DESCRIPTION***
Land Management	Provide consulting services related to the buying and selling of real estate; including site appraisals and site maintenance services.
Corporate Services	Provide office space, furnishings, and equipment. Provide consulting services related to maintenance of owned and leased facilities.
Building Space and Office Services	Bill rent and carrying charges for building space occupied.
Equipment Rentals	Lease short-term equipment rentals.
Materials and Supplies (inventory transfers)	Provide materials from storerooms. Charges include the cost of the materials and supplies and appropriate stores overheads. Stores overheads include costs associated with purchasing and maintaining the materials and supplies inventory.
Telecom Communication Services & Maintenance	Effective January 1, 2014, AEP Generation Resources (AGR) has contracted with Ohio Power Company (OPCo)

CATEGORY	***DESCRIPTION***
	to provide bandwidth, local phone service and maintenance services on telecommunication equipment owned by AGR. These services provided by OPCo will be billed to AGR at the higher of cost or market, in compliance with the asymmetric pricing rules.

PRODUCTS AND SERVICES PROVIDED TO REGULATED UTILITIES BY NON-REGULATED AFFILIATES

The following table describes the nature of products and services provided to the AEP System's regulated utilities by non-regulated affiliates:

CATEGORY	***DESCRIPTION***
Water Transportation and Coal Handling	Provide barging and services at transfer terminals and other coal handling facilities.
Railcar Usage	Usage of railcars by other companies.
Coal Handling	Provides trans-loading services at Cook Terminal.
Testing Services	USTI provides environmental testing services to our generation facilities. These services provided by USTI will be billed to the regulated generation facilities at the lower of cost

	or market, in compliance with the asymmetric pricing rules.

PRODUCTS AND SERVICES PROVIDED BY REGULATED UTILITIES TO EACH OTHER (Including Coal Mining Subsidiaries)

The following table describes the nature of products and services provided by the AEP System's regulated utilities to each other:

CATEGORY	***DESCRIPTION***
Materials and Supplies (inventory transfers)	Materials supplied from company storerooms shall include the material cost and stores overheads. Overheads include costs associated with purchasing and maintaining materials and supplies inventory.
Equipment Maintenance	Provide personnel and services to perform regular and emergency equipment repairs (primarily for operating plant equipment).
Simulator Training	Provide personnel and facility to train power plant personnel on the operation of 1300 MW units.
Building Space and Office Services	Billing of rent and carrying charge for building space occupied.
Water Transportation, Coal and Consumables	Provide barging and services at transfer

CATEGORY	***DESCRIPTION***
Handling, and Gypsum	terminals and other coal handling facilities.
Railcar Maintenance	Billing for routine inspection and repair work on railcar hopper fleet.
Railcar Usage	Usage of railcars by other companies.
Mining (including mine shutdown costs)	Affiliated companies mine and provide coal and lignite to electric utilities on a cost reimbursement basis.
Interconnection Agreement (power purchases and sales)	Sharing of power production and off-system sales and purchases among AEP System generating companies.
Emission Allowances	Sharing of emission allowances and associated costs and benefits (including sales and purchases with non-affiliated parties).
Emergency Assistance	Provide personnel to restore electric service interrupted by natural disasters.
EHV Transmission System	Sharing of costs incurred regarding the ownership, operation and maintenance of AEP’s extra-high voltage (EHV) transmission system.

CATEGORY	***DESCRIPTION***
Energy Distribution System	Provide personnel and services to perform engineering, metering, drafting, line work, customer services, right-of-way maintenance work, design of construction projects, contract administration and administrative planning.
Energy Transmission	Provide personnel and services to perform transmission line work, protection & control, and station and engineering work.
Energy Delivery Support	Provide personnel and services to perform measurements, telecommunications, forestry and real estate work.
Administrative Support	Provide personnel and services to perform environmental, governmental affairs, fleet management, building services and mail services.
Hydro Plant	Provide supervision, maintenance and operation of hydro plant and associated facilities.
Joint Facilities	Share costs of operations and maintenance of jointly owned facilities (primarily generating

CATEGORY	***DESCRIPTION***
	plants and HVDC transmission facilities).
Capitalized Spare Parts	Capitalized spare parts are sold by the utilities to each other at cost.
Coal Supply	Sale of Coal to the operating companies.
Waste Disposal	Provide waste handling and landfill services
Consumables Handling	Provide Services for transloading UREA.
Coal Handling	Provides trans-loading services at Cook Terminal.
Transmission Training	Provide transmission employees with training.

SUMMARY	The AEP System Utility Money Pool and the AEP System Nonutility Money Pool are arrangements structured to meet the short-term cash requirements of their participants. The operation of the two Money Pool arrangements is designed to match, on a daily basis, the available cash and borrowing requirements of participants, thereby minimizing the need to borrow from external sources.
AUTHORITY	The AEP System Utility Money Pool and the AEP System Nonutility Money Pool operate consistently with the terms and conditions of their respective agreements. The AEP System Utility Money Pool Agreement is filed with the Federal Energy Regulatory Commission (FERC).
PARTICIPANTS	The AEP System Utility Money Pool participants are certain of AEP regulated direct and indirect subsidiaries as well as certain nonutility subsidiaries. The AEP System Nonutility Money Pool Agreement participants are certain of AEP unregulated direct and indirect subsidiaries. Each participant may withdraw any of its funds from the respective Money Pool to which it belongs at any time upon notice to American Electric Power Service Corporation (AEPSC).
AGENT	AEPSC acts as the administrative agent of the Utility and Nonutility Money Pools, and is a participant in the Utility Money Pool.
FUNDING ENTITIES	AEP may engage in various types of short-term financings to fund the daily needs of the money pools. AEP Utilities (formerly Central and South West Corporation) may engage in various types of short-term financings to fund the daily needs of the Utility Money Pool only.

FUNDING ENTITIES (Cont'd)

AEP Utility Funding LLC was formed to fund the Utility Money Pool and AEP Nonutility Funding LLC was formed to fund the Nonutility Money Pool. Any funds transferred to the Money Pool will flow through the applicable Funding LLC. The Utility Funding LLC may obtain funds from external sources, AEP or AEP Utilities. The Nonutility Funding LLC will obtain its funds from AEP. The Funding LLCs are solely financial conduits.

RULES

American Electric Power Company, Inc. (AEP), AEP Utilities, Inc. (AEP Utilities), AEP Utility Funding LLC, and AEP Nonutility Funding LLC will not borrow funds from the Utility or Nonutility Money Pools or their participants.

Participants in the Nonutility Money Pool will not engage in lending and borrowing transactions with participants of the Utility Money Pool.

Each participant, except AEP and AEP Utilities, AEP Utility Funding LLC, and AEP Nonutility Funding LLC has the right to borrow from its respective Money Pool from time to time, subject to the availability of funds and other limitations. No participant is obligated to borrow from its respective Money Pool if lower cost funds can be obtained from its own external borrowing.

PROCESS

Available funds in the treasuries of the participants in the individual Utility and Nonutility Money Pools are individually "pooled" together. Within each money pool the cash position of each Money Pool participant is determined on a daily basis. The pooled funds are either loaned to other participants within the pool or invested in short-term cash instruments.

If the cash needs of the Utility and/or Nonutility Money Pools exceed the pooled funds, additional funds are raised through external borrowings from the sale of commercial paper notes as well as certain other means to the extent permitted by law and regulatory orders.

A daily interest rate is calculated for each money pool and applied to all participant borrowings and investments.

The interest rate for the Utility Money Pool is the composite weighted-average daily effective cost incurred by AEP, and/or AEP Utilities and/or AEP Utility Funding LLC for short-term borrowings from external sources or an equivalent rate when there is no external borrowing.

The interest rate for the Nonutility Money Pool is the composite weighted-average daily effective cost incurred by AEP for short-term borrowings from external sources or an equivalent rate when there is no external borrowing, plus a margin if the Participant's internal credit rating is lower than that of the Leading Parties.

If surplus funds exist in the treasuries of the Utility and/or Nonutility money pools, an external investment is made on behalf of the respective money pool with the surplus.

Interest income related to external investment of surplus funds is calculated daily and allocated back to the lending participants based on their relative contribution to the surplus.

Money Pool participants are also charged a pro rata cost of certain expenses associated with their borrowing program, including fees associated with bank lines of credit, rating agencies, and the issuing and paying agent.

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Section

Affiliate Transactions

Subject

RESEARCH AND DEVELOPMENT

SUMMARY	Research and development (R&D) projects are generally managed by AEPSC on behalf of other AEP System companies. The services performed by AEPSC are billed to the respective parties through the AEPSC billing system. Every shared project is billed using one of the approved Allocation Factors (see the Appendix to this manual for a complete list of approved Allocation Factors).
	In many cases, an AEP System operating company provides the site for conducting the R&D activity and/or procures the equipment and materials needed to conduct the research. In these cases, the operating company acts as the lead company for all other participants and is responsible for the payment of all costs it incurs on behalf of the other participants.
	The costs incurred by the lead company are shared with and billed to the other AEP participants through a separate R&D accounting and billing process. The R&D accounting and billing process uses the same Allocation Factor for each project that AEPSC uses to bill its support costs.
PROCEDURE	Operating company billings for R&D are performed on a fully-allocated cost basis (i.e., the billings include both direct and indirect costs).
Non-Productive Pay	The cost of employee vacations, holidays, jury duty and other paid absences are accrued and loaded on to labor dollars.
Fringe benefits Procedure	The cost of fringe benefits such as pension expense is loaded on to labor dollars.

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Section

Affiliate Transactions

Subject

RESEARCH AND DEVELOPMENT

A&G OVERHEADS	Administrative and general (A&G) overheads are loaded to R&D projects in the R&D accounting and billing process based on the labor dollars charged to each project.
Direct Costs	All direct costs of a R&D project, including productive labor, are captured along with the indirect costs described above.
BILLING	The lead company of any shareable R&D project will bill its associates their respective share of the incurred R&D costs. The costs billed to the associate companies will be exclusive of any costs that are incurred by AEPSC since such costs are appropriately allocated through the AEPSC work order billing system. The lead company will retain its share of any incurred costs.

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Document Number **01-03-06**

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Section

Affiliate Transactions

Subject

FINANCIAL TRANSACTIONS

SUMMARY

The AEP System companies, although legally separated, operate on an integrated basis as permitted by law and regulation. Financial transactions are conducted on a regular basis in support of the integrated activities.

FINANCIAL TRANSACTIONS

The following table provides a summary of the primary financial transactions the AEP System companies conduct with each other that are not covered elsewhere in this Section of this manual:

CATEGORY	***DESCRIPTION***
Loans	Debt obligations.
Capital Contributions	Common stock purchases as well as paid-in capital transactions.
Accounts Receivables Factoring	AEP Credit, Inc. (formerly CSW Credit, Inc.) buys the accounts receivables of certain of the electric utility affiliates.
Credit Line Fees	Credit line fees are shared among AEP System companies.
Dividend Payments	Dividend payments are made by subsidiaries to their parent companies.
Real and Personal Property	Title to and/or rights in real or personal property acquired and held by an AEP affiliate as Agent for another AEP affiliate.

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Affiliate Transactions

Subject

FINANCIAL TRANSACTIONS

CATEGORY	***DESCRIPTION***
Employee Loans, Accrued Compensation, Employee Relocation Expenses and Other Employee-Related Items	When an employee transfers from one AEP company to an affiliate, the receiving company pays the employee’s relocation expenses. In addition, any amounts due to or from the employee are transferred to the receiving company from the sending company.
Money Pool	An arrangement designed to match the available cash and borrowings requirements of participants to minimize the need for external borrowings.

NOTE: Also see Document Numbers **01-03-04, 01-03-05** and **01-03-08** for a discussion of the AEP Money Pool, Research & Development cost sharing and Convenience Payments, respectively.

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Document Number 01-03-07

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Affiliate Transactions

Subject

INTELLECTUAL PROPERTY

SUMMARY	AEP Pro Serv, Inc. has entered into agreements with American Electric Power Service Corporation (AEPSC) and certain electric utility subsidiaries within the AEP System. These agreements, among other things, extend to the resale and licensing of property protected by copyright, patent or trademark laws (herein referred to as intellectual property).
TERMS AND CONDITIONS FOR USE OF INTELLECTUAL PROPERTY BY AEP PRO SERV	If AEP Pro Serv sells or licenses to non-affiliates intellectual property developed by AEPSC or any other AEP System company, such companies shall receive a percentage of the net profits and AEP Pro Serv will receive a commission by having AEP Pro Serv pay the AEP System company that developed the intellectual property the amounts noted in the following table:

REVENUE SHARING PROVISIONS
1. 70% of the revenues from the intellectual property until the AEP System company that developed the intellectual property recovers its programming and development costs; and 2. 20% of such revenues thereafter.

TERMS AND CONDITIONS FOR THE USE OF INTELLECTUAL PROPERTY DEVELOPED BY AEP PRO SERV.	Intellectual property developed by AEP Pro Serv will be made available to all associates in the AEP holding company system without charge, except for actual expenses incurred by AEP Pro Serv in connection with making such intellectual property so available.

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Section

Affiliate Transactions

Subject

SERVICE CORPORATION CONVENIENCE PAYMENTS

SUMMARY

American Electric Power Service Corporation (AEPSC) provides services to other companies in the AEP Holding Company System. To the extent possible, the expenditures incurred by AEPSC should pertain exclusively to the services it performs.

AEP POLICY

AEP's policy is to minimize AEPSC convenience payments. However, in some situations, AEPSC makes payments on behalf of other System companies as a matter of convenience. Generally, these convenience payments are made in an emergency situation or for cost-saving or timesaving purposes. The requester must recommend an allocation method for any Convenience Payment that pertains to two or more companies.

The distribution of the convenience payment among the appropriate companies will be provided by either the requester of the convenience payment or by AEPSC personnel acting on behalf of the requester. The distribution of the convenience payment can be provided on the face of the invoice to be paid, based upon anticipated benefits to be derived by the appropriate companies, or based upon existing AEPSC allocation methods. The most appropriate and/or reasonable method will be used for each specific convenience payment based on the type of transaction.

REPORTING REQUIREMENTS

Annually AEPSC is required to report the amount paid during the past calendar year for convenience payments. The required information must be included in AEPSC's annual report that is filed with the Federal Energy Regulatory Commission (FERC)on FERC Form 60.

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Cost Allocation Manual

Section

Introduction

Subject

OVERVIEW (GUIDELINES)

SUMMARY	AEP has internal (i.e., Corporate) guidelines for cost allocation and inter-company billings. Federal and state authorities, either through legislation or formal rule making, have established cost allocation methods and affiliate transaction requirements.
CORPORATE	AEP has established corporate policies and procedures for cost allocation and billing. Its cost allocation process includes both direct costs and indirect costs. Its inter-company billing process includes both direct billings to a single company and shared billings to a group or class of companies.
FEDERAL REGULATION	The Federal Energy Regulatory Commission (FERC) regulates the AEP System’s cost allocation process as well as the transactions that take place among the AEP System companies. AEP prices all transactions among the affiliate companies in the AEP System in accordance with the “at cost” standard, which was carried forward by the FERC under the PUHCA 2005.
STATE COMMISSION RULES	AEP’s eleven state commissions, to some degree, have established rules and regulations or other requirements relative to AEP’s cost allocation practices and affiliate transactions. State commission authority in these areas, for the most part, is based on their authority to establish rates for retail customers.

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OVERVIEW

SUMMARY	AEP's internal guidelines applicable to cost allocations are designed to result in a fair and equitable allocation of costs. Policies and procedures have also been formulated to meet regulatory standards both for cost allocation and affiliate transactions.
COST ALLOCATION POLICIES AND PROCEDURES	Each AEP subsidiary maintains separate books and records. Transactions are coded and processed in a manner that meets all regulatory requirements. Proper audit trails are maintained so that costs can be traced from source documents all the way through the applicable accounting and billing systems.
	02-02-02
THE COST ALLOCATION PROCESS	Unless otherwise exempted, the AEP companies allocate costs between regulated and non-regulated operations, on a fully-distributed cost basis. Fully-distributed costs include all direct costs plus an appropriate share of indirect costs.
	02-02-03
COST POOLING AND COST ASSIGNMENT	Indirect costs are pooled and assigned to multiple companies or company segments in accordance with the relative benefits received or by other equitable means.
	02-02-04
ACCOUNT DESIGNATIONS	The operation and maintenance expense accounts in the Federal Energy Regulatory Commission's (FERC's) uniform system of accounts break functionally between regulated and non-regulated expenses. Certain administrative and general expenses

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OVERVIEW

ACCOUNT DESIGNATIONS Cont'd)	include costs that can be attributed to both regulated and non-regulated activities. Some of AEP's generation has been restructured as a competitive activity, and therefore, the power production accounts in the FERC's system of accounts become non—regulated accounts.

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COST ALLOCATION POLICIES AND PROCEDURES

SUMMARY

Cost allocation is the process of assigning a single cost to one or more company or company segments on the basis of the relative benefits received or other equitable basis. This document summarizes the underlying cost allocation policies and procedures that are applied on a corporate-wide basis by all AEP companies.

POLICIES AND PROCEDURES

AEP's cost accounting and cost allocation policies and procedures shall not result in any cost subsidies among or between regulated and non-regulated operations. Unless otherwise exempted, all affiliate transactions for services or products will be conducted at fully allocated cost. For the transfer of capital assets, fully allocated cost shall equal the net book value of the capital asset.

The term “affiliate transactions” refers to all transactions between the utility and any separate affiliate company, both regulated and non-regulated, including all transactions between a utility's regulated operations (above-the-line) and non-regulated operations (below-the-line).

Basic Goal

The basic goal of AEP's cost allocation policies and procedures are threefold:

- to ensure a fair and equitable distribution of costs among all benefiting parties
- to meet pertinent regulatory requirements
- to minimize the time and expense needed to record, audit and report transactions.

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COST ALLOCATION POLICIES AND PROCEDURES

Separate Books and Records

Each subsidiary of AEP shall maintain separate books and records and make maximum use of common accounting and business systems without violating any federal or state imposed code of conduct provisions relative to sensitive customer or non-public information.

Accounting Transactions

All financial accounting transactions will be recorded in accordance with corporate accounting policy using the appropriate chartfield values for each transaction. Each transaction will be recorded in accordance with the FERC Uniform System of Accounts as applicable to each subsidiary or affiliate.

Cross-Subsidies

AEP's cost accounting and cost allocation methods or procedures shall not result in any cost subsidies among or between regulated and non-regulated operations.

Cost Allocation

Factors to be considered in the Allocation of individual items of cost include, among other things:

- the relationship of the individual cost to the benefiting company or company segments
- generally accepted accounting principles
- best practices
- regulatory principles
- reasonableness of results

Audit Trail

A key requirement for allocating costs for affiliate transactions is the maintenance of adequate audit trails. The following audit trail standards shall be maintained for all transactions:

- vendor invoices, employee time records and expense accounts, general ledger journal entries and similar documentation will be available and accessible to adequately support the accuracy and validity of individual transactions
- all supporting documentation will be retained in accordance with the applicable regulatory requirements for records retention
- all posting to the providers' books of account or summary ledgers will be identifiable with the individual transactions that make up the total amount of the posting.

Transfer Pricing of Affiliate Transactions

The predominant pricing standard among AEP's various regulatory jurisdictions for affiliate transactions is "fully-allocated cost." However, in certain jurisdictions and instances, the substantiation of market prices may be required because of state code of conduct or other rules or regulations.

For billing purposes, non-tariff products and services either purchased by or sold by one of AEP's regulated utilities will be priced at "fully-allocated cost".

In the case of products and services, "fully-allocated cost" approximates market value in most situations since the parties are simply sharing costs that reflect current market prices.

For the transfer of capital assets between an AEP regulated utility and an affiliate, "fully-allocated cost" shall equal the net book value of the asset (i.e., original cost less depreciation).

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COST ALLOCATION POLICIES AND PROCEDURES

ACCESS TO BOOKS AND RECORDS	All lawful requests by regulators to obtain access to the books and records of an affiliate of a regulated utility for the purpose of setting the utility's cost-based rates shall be honored in a timely manner.

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THE COST ALLOCATION PROCESS

SUMMARY

AEP allocates costs to regulated and non-regulated operations on a fully-distributed cost basis. Fully distributed costs include all direct costs plus an appropriate share of indirect (and common) costs.

DIRECT COSTS

Direct costs can be identified with a particular activity and can be incurred on behalf of one or more companies or affiliates.

INDIRECT COSTS

Indirect costs cannot be identified with a particular activity and must be charged to the appropriate activity or activities to which they relate using relevant cost allocators. Indirect costs include, but are not limited to, corporate or business unit overheads, general and administrative overheads, and certain taxes.

COMMON AND JOINT COSTS

Common and joint costs, as distinguished from indirect costs, are costs that are of joint benefit between regulated and non-regulated business operations. These costs can include both direct and indirect costs.

COST EXAMPLES

The following table provides examples of the expenses included in each cost category:

Direct costs	Direct labor; direct materials
Indirect costs	Board of Directors' fees; FICA tax; interest expense; other elements of Internal Support Costs and departmental overhead.
Common costs	Depreciation or rent expense on shared buildings; the expenses incurred in operating a common payroll system

BASIC PROCESS

AEP allocates costs among regulated and non-regulated business operations following three basic steps:

1. To the maximum extent possible, within reasonable cost benefit standards, costs are collected and classified on a direct charge basis.

2. All costs, both direct and indirect, are attributed to activities (i.e., projects, products or services) which, by their very nature, are regulated, non-regulated, common or joint.

3. The costs of common or joint activities are allocated using either an output measure of the activity performed or the primary cost driver (or a relevant proxy in the absence of a primary cost driver).

BILLINGS TO AFFILIATES

Any costs incurred for the benefit of only one client or affiliate are billed 100% to that client or affiliate.

Any costs incurred for the benefit of more than one client or affiliate are billed to the clients or affiliates for which the related service was performed using cost-causative allocation factors of the nature described in Step 3 of the basic allocation process (see above). For example, the cost accumulated for processing payroll is allocated and billed based on the ratio of each client's or affiliate's number of employees to the total number of employees of all clients or affiliates receiving the service.

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COST POOLING AND COST ASSIGNMENT

SUMMARY

The financial accounting systems used by the AEP System companies are designed to pool allocable costs in a manner that leads to a fair and equitable distribution of costs among all affiliated companies and between regulated and non-regulated operations.

UNDERLYING PRINCIPLE

The underlying principle in cost allocation is that the results must be fair and equitable. To meet this standard, the results must be reasonable and take into account the relative benefits received from each cost pool.

POOLING METHODOLOGY

In order to perform fair and equitable cost allocations, AEP's financial accounting systems are designed to capture and pool costs at three basic levels:

- direct costs are costs which can be specifically assigned to final cost objectives;
- common or joint costs are costs which apply to more than one cost objective and can be attributed to them in reasonable proportion to the benefits received; and
- overhead costs relate to the overall operations of the business and, as such, have no direct relationship to any particular cost objective.

Sub-Pools

Common and joint costs along with overhead costs are further accumulated in various cost groupings (sub-pools). Examples include:

- salary-related costs (also known as fringes)
- compensated absences (i.e., non-

productive pay)
- building costs
- technology costs
- general and administrative overhead
- construction overhead

COST ASSIGNMENT

The AEP System pools and allocates costs at each level on a legal entity basis. That is, the costs incurred by one company do not affect the level of costs allocated by another company. Separate books and records are maintained for each company.

All companies assign direct costs on a 100% basis while common or joint costs are assigned or charged to multiple cost objectives in accordance with the relative benefits received or by other equitable means. Overhead costs are charged using relatable, cost-causative factors such as labor dollars, and total cost input.

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ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

SUMMARY

As required by the Commonwealth of Kentucky's House Bill No. 897 [Section 4(f)], the Cost Allocation Manual (CAM) maintained by the electric utility must provide a report that identifies whether the costs contained in each account (or sub-account) of the Uniform System of Accounts (i.e., the USoA) are attributable to regulated operations, non-regulated operations, or are joint costs in nature. A description of the methodology used to apportion the costs shall also be included. The allocation methodology must be consistent with the provisions of Section 3 of House Bill No. 897.

While this document has been prepared primarily to satisfy Kentucky's CAM requirement, the account designations included in the accompanying chart also apply to AEP's other electric utilities.

ACCOUNT DESIGNATIONS

The chart which begins on the following page identifies those USoA operation and maintenance accounts that are considered to be regulated, non-regulated or joint. The chart pertains to all of AEP's regulated utilities to the extent that they use each account. As generation becomes deregulated in certain state jurisdictions, the accounts for power production expenses will become non-regulated.

COST ALLOCATION

To the extent possible, costs are charged directly to either regulated or non-regulated operations as appropriate. Those "joint" costs that can not be directly charged are allocated between regulated and non-regulated operations based on the nature of the cost, using the appropriate allocation basis from the List of Approved Allocation Factors used for Service Company billings.

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ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

CHART

FERC Account	Description	Reg.	Non Reg.	Joint
	Power Production Expenses			
500.0	Oper Supervision & Engineering	No	No	Yes
501.0	Fuel	No	No	Yes
502.0	Steam Expenses	No	No	Yes
503.0	Steam from Other Sources	No	No	Yes
504.0	Steam Transferred-Credit	No	No	Yes
505.0	Electric Expenses	No	No	Yes
506.0	Misc Steam Power Expenses	No	No	Yes
507.0	Rents	No	No	Yes
508.0	Oper Supplies and Expenses	No	No	Yes
509.0	Allowances	No	No	Yes
510.0	Maint Supv & Engineering	No	No	Yes
511.0	Maintenance of Structures	No	No	Yes
512.0	Maintenance of Boiler Plant	No	No	Yes
513.0	Maintenance of Electric Plant	No	No	Yes
514.0	Maintenance of Misc Steam Plt	No	No	Yes
515.0	Maintenance of Steam Production Plant	No	No	Yes
517.0	Oper Supervision & Engineering	No	No	Yes
518.0	Nuclear Fuel Expense	No	No	Yes
519.0	Coolants and Water	No	No	Yes
520.0	Steam Expenses	No	No	Yes
521.0	Steam from Other Sources	No	No	Yes
522.0	Steam Transferred-Credit	No	No	Yes
523.0	Electric Expenses	No	No	Yes
524.0	Misc Nuclear Power Expenses	No	No	Yes
525.0	Rents	No	No	Yes
528.0	Maintenance Supervision and engineering	No	No	Yes
529.0	Maintenance of Structures	No	No	Yes
530.0	Maintenance of Reactor Plant Equipment	No	No	Yes
531.0	Maintenance of Electric Plant	No	No	Yes
532.0	Maintenance of Misc Nuclear Plant	No	No	Yes
535.0	Operation Supervision and Engineering	No	No	Yes
536.0	Water for Power	No	No	Yes
537.0	Hydraulic Expenses	No	No	Yes

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ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
	Power Production Expenses (Cont'd)			
538.0	Electric Expenses	No	No	Yes
539.0	Misc Hydr Power Generation Exp	No	No	Yes
540.0	Rents	No	No	Yes
540.1	Operation Supplies and Expenses	No	No	Yes
541.0	Maintenance Supervision and Engineering	No	No	Yes
542.0	Maintenance of Structures	No	No	Yes
543.0	Maintenance of Reservoirs, Dams and Waterways	No	No	Yes
544.0	Maintenance of Electric Plant	No	No	Yes
545.0	Maintenance of Misc Hydraulic Plant	No	No	Yes
545.1	Maintenance of Hydraulic Production Plant	No	No	Yes
546.0	Operation Supervision and Engineering	No	No	Yes
547.0	Fuel	No	No	Yes
548.0	Generation Expenses	No	No	Yes
549.0	Misc Oth Pwr Gen - Gas Turbine	No	No	Yes
550.0	Rents	No	No	Yes
550.1	Operation supplies and expenses	No	No	Yes
551.0	Maint Supv & Engineering	No	No	Yes
552.0	Maintenance of Structures	No	No	Yes
553.0	Maintenance of Generating and Electric Plant	No	No	Yes
554.0	Maintenance of Misc Other Power Generation Plant	No	No	Yes
554.1	Maintenance of Other Power Production Plant	No	No	Yes
555.0	Purchased Power	No	No	Yes
556.0	Sys Control & Load Dispatching	No	No	Yes
557.0	Other Expenses	No	No	Yes
	Transmission Expenses			
560.0	Oper Supervision & Engineering	Yes	No	No
561.1	Load Dispatch--Reliability	Yes	No	No
561.2	Load dispatch—Monitor and	Yes	No	No

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Corporate

Subject

ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
	operate transmission system			
561.3	Load dispatch—Transmission service and scheduling	Yes	No	No
561.4	Scheduling system control and dispatch services	No	No	Yes
561.5	Reliability planning and standards development	Yes	No	No
561.6	Transmission service studies	Yes	No	No
561.7	Generation interconnection studies	Yes	No	No
561.8	Reliability planning and standards development services	Yes	No	No
562.0	Station Expenses	Yes	No	No
563.0	Overhead Line Expenses	Yes	No	No
564.0	Underground Line Expenses	Yes	No	No
565.0	Transmssion of Elect by Others	Yes	No	No
566.0	Misc Transmission Expenses	Yes	No	No
567.0	Rents	Yes	No	No
567.1	Operation Supplies and Expenses	Yes	No	No
568.0	Maint Supv & Engineering	Yes	No	No
569.0	Maintenance of Structures	Yes	No	No
569.1	Maintenance of computer hardware	Yes	No	No
569.2	Maintenance of computer software	Yes	No	No
569.3	Maintenance of communication equipment	Yes	No	No
569.4	Maintenance of miscellaneous regional transmission plant	Yes	No	No
570.0	Maint of Station Equipment	Yes	No	No
571.0	Maintenance of Overhead Lines	Yes	No	No
572.0	Maint of Underground Lines	Yes	No	No
573.0	Maint of Misc Transmssion Plt	Yes	No	No
574.0	Maintenance of Transmssion Plant	Yes	No	No
	Regional Market Expenses			
575.1	Operation Supervision	Yes	No	No
575.2	Day-ahead and real-time	Yes	No	No

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Corporate

Subject
ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
	market facilitation			
575.3	Transmission rights market facilitation	Yes	No	No
575.4	Capacity market facilitation	Yes	No	No
575.5	Ancillary services market facilitation	Yes	No	No
575.6	Market monitoring and compliance	Yes	No	No
575.7	Market facilitation, monitoring and compliance services	Yes	No	No
575.8	Rents	Yes	No	No
576.1	Maintenance of structures and improvements	Yes	No	No
576.2	Maintenance of computer hardware	Yes	No	No
576.3	Maintenance of computer software	Yes	No	No
576.4	Maintenance of communication equipment	Yes	No	No
576.5	Maintenance of miscellaneous market operation plant			
	Distribution Expenses			
580.0	Oper Supervision & Engineering	Yes	No	No
581.0	Load Dispatching	Yes	No	No
581.1	Line and Station Expense	Yes	No	No
582.0	Station Expenses	Yes	No	No
583.0	Overhead Line Expenses	Yes	No	No
584.0	Underground Line Expenses	Yes	No	No
585.0	Street Lighting & Signal Sys Exp	Yes	No	No
586.0	Meter Expenses	Yes	No	No
587.0	Customer Installations Exp	Yes	No	No
588.0	Miscellaneous Distribution Exp	Yes	No	No
589.0	Rents	Yes	No	No
590.0	Maint Supv & Engineering	Yes	No	No
591.0	Maintenance of Structures	Yes	No	No
592.0	Maint of Station Equipment	Yes	No	No
592.1	Maintenance of Structures and Equipment	Yes	No	No
593.0	Maintenance of Overhead	Yes	No	No

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Corporate

Subject

ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
	Lines			
594.0	Maint of Underground Lines	Yes	No	No
594.1	Maintenance of Lines	Yes	No	No
595.0	Maint of Line Transformers	Yes	No	No

	Distribution Expenses (Cont'd)			
596.0	Maint of Street Lighting & Signal Systems	Yes	No	No
597.0	Maintenance of Meters	Yes	No	No
598.0	Maint of Misc Distribution Plt	Yes	No	No
	Customer Accounts Expenses			
901.0	Supervision - Customer Accts	Yes	No	No
902.0	Meter Reading Expenses	Yes	No	No
903.0	Cust Records & Collection Exp	Yes	No	No
904.0	Uncollectible Accounts	Yes	No	No
905.0	Misc Customer Accounts Exp	Yes	No	No
	Customer Services and Informational Expenses			
907.0	Supervision - Customer Service	Yes	No	No
908.0	Customer Assistance Expenses	Yes	No	No
909.0	Information & Instruct Advertising Exp	Yes	No	No
910.0	Misc Cust Svc & Informational Exp	Yes	No	No
	Sales Expenses			
911.0	Supervision - Sales Expenses	Yes	No	No
912.0	Demonstrating & Selling Exp	Yes	No	No
913.0	Advertising Expenses	Yes	No	No
916.0	Miscellaneous Sales Expenses	Yes	No	No
	Administrative and General Expenses			
920.0	Administrative & Gen Salaries	No	No	Yes
921.0	Office Supplies and	No	No	Yes

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ACCOUNT DESIGNATIONS (Regulated, Non-Regulated and Joint)

FERC Account	Description	Reg.	Non Reg.	Joint
	Expenses			
923.0	Outside Services Employed	No	No	Yes
924.0	Property Insurance	No	No	Yes
925.0	Injuries and Damages	No	No	Yes
926.0	Employee Pensions & Benefits	No	No	Yes
928.0	Regulatory Commission Exp	No	No	Yes
930.1	General Advertising Expenses	No	No	Yes
930.2	Misc General Expenses	No	No	Yes
931.0	Rents	No	No	Yes
935.0	Maintenance of General Plant	No	No	Yes

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Federal Regulation

Subject

OVERVIEW

SUMMARY

Effective February 8, 2006, the Public Utility Holding Company Act of 1935 was repealed. Jurisdiction over certain holding company related activities has been transferred to the Federal Energy Regulatory Commission under the Public Utility Holding Company Act of 2005.

FERC REGULATION

The business of transmitting and selling electric energy in interstate commerce is regulated through Part II of the Federal Power Act.

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Section

Federal Regulation

Subject

FERC Regulation

SUMMARY

The transmission of electric energy in interstate commerce and the sale of electric energy at wholesale in interstate commerce is regulated by the Federal Energy Regulatory Commission (FERC) under the Federal Power Act.

PUHCA 2005

The Energy Policy Act of 2005 repealed the Public Utility Holding Company Act of 1935 effective February 8, 2006 and replaced it with the Public Utility Holding Company Act of 2005. With the repeal of PUHCA 1935, the Securities and Exchange Commission no longer has jurisdiction over the activities of registered holding companies. Jurisdiction over certain holding company related activities has been transferred to the Federal Energy Regulatory Commission. Specifically, FERC has jurisdiction over the issuances of securities of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets, and mergers with another electric utility or holding company. In addition, both FERC and state regulators will be permitted to review the books and records of any company within a holding company system. FERC also has jurisdiction over certain affiliate transactions. As part of the implementation of the Public Utility Holding Company Act of 2005, FERC has adopted rules addressing these various issues. The pertinent rules may be found at 18 C.F.R. Part 366.

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State Commission Rules

Subject

OVERVIEW

SUMMARY

AEP's state commissions have established certain rules and requirements relative to affiliate transactions. The requirements generally fall into four broad categories:

- they need to maintain a cost allocation manual or other documentation
- transfer pricing rules
- reporting requirements
- audit requirements.

ARKANSAS

Arkansas requirements can be found in Arkansas Public Service Commission Order 7 of Docket 06-112-R, dated May 25, 2007.

02-04-02

INDIANA

Indiana's requirements can be found in the Indiana Code as well as various orders of the Indiana Utility Regulatory Commission.

02-04-03

KENTUCKY

Kentucky's requirements are contained in Kentucky Revised Statutes (KRS) 278.2201 thru 278.2219; Kentucky Public Service Commission Regulation 807KAR 5:080 and in various orders of the Kentucky Public Service Commission.

02-04-04

LOUISIANA

Louisiana's requirements can be found in the Louisiana Public Service Commission's Order No. U-23327, dated September 16, 1999, subject to the conditions set forth in the Stipulation and Settlement attached as Appendix A to the Order.

02-04-05

MICHIGAN

Michigan's requirements are contained in various orders of the Michigan Public Service Commission, including its Order Approving Settlement Agreement dated December 16, 1999, in Case No. U-12204, and its Opinion and Order, dated December 4, 2000, in Case No. U-12134.

02-04-06

OHIO

Ohio's requirements are captured in the corporate separation rules adopted by the Public Utilities Commission of Ohio in Case No. 99-1141-EL-ORD, as amended in Case Nos. 04-48-EL-ORD and 08-777 – EL – ORD, and in various orders of the Commission.

02-04-07

OKLAHOMA

Oklahoma's requirements are focused on the Oklahoma Corporation Commission's ability to access the books and records of Public Service Corporation of Oklahoma and its AEP affiliates as stated in the Stipulation, dated as of April 16, 1999, in Cause No. PUD 980000444.

02-04-08

TENNESSEE

Tennessee has no specific rules and requirements applicable to cost allocations and affiliate transactions.

02-04-09

TEXAS

Texas' requirements to a large degree are contained in §36.058 of the Texas Public Utility Regulatory Act and the rules of the Public Utility Commission of Texas.

02-04-10

VIRGINIA

Virginia's requirements can be found in the

Code of Virginia and in the regulations and in orders of the Virginia State Corporation Commission.

02-04-11

WEST VIRGINIA

West Virginia's requirements can be found in the West Virginia Code and in orders of the Public Service Commission of West Virginia.

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State Commission Rules

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ARKANSAS RULES AND REQUIREMENTS

SUMMARY

The Arkansas Public Service Commission adopted Affiliate Transaction Rules May 25, 2007. The purpose of the rules is to ensure that all transactions among or between a public utility and any affiliates or divisions do not result in rates which are unreasonable and in violation of Arkansas statutes; to ensure that the rates charged by public utilities do not provide any subsidy to affiliates or divisions of the public utility which are involved in non-utility activities or which provide services to the public utility; to prevent anti-competitive behavior, and market manipulation or market power; and to prevent financial risk to rate-regulated public utility operations which may arise from business endeavors of an unregulated affiliate.

The following summarizes the Affiliate Transaction Rules as adopted.

DOCUMENTATION REQUIREMENTS

The Commission's documentation requirements applicable to affiliate transactions are provided in the table below:

SUBJECT	REQUIREMENT
Record Keeping Rule IV	A public utility is to keep books and records separately from the books and records of its affiliates and to maintain such books and records in accordance with applicable rules and orders of the Commission, and with Generally Accepted Accounting Principles as amended. Such books and records shall contain all information

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SUBJECT	REQUIREMENT
	necessary to identify all affiliate transactions in which a public utility participated; and identify and allocate or impute all revenues and costs (both direct and indirect) associated with all such affiliate transactions. Upon the creation of a new affiliate that will participate with a public utility, the utility shall, no later than 60 days after the creation of the affiliate, notify the Commission by letter to the Secretary of the Commission of the creation of the new affiliate, and the notice shall include an explanation of how the public utility will implement these rules with respect to the new affiliate.
	Each public utility shall maintain, for at least five years, records of each affiliate transaction in which it participated and the records shall: a. be made contemporaneously with each affiliate transaction; b. be in a readily retrievable format; and c. include, for each affiliate transaction: 1. identify of the

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SUBJECT	REQUIREMENT
	affiliate; 2. commencement and termination dates of the transaction; 3. description of the affiliate transaction, including the nature and quantity of value provided and received; 4. the dollar amount of the transaction and the manner in which such dollar amount was calculated; 5. all other terms of the transaction; 6. the direct and indirect costs associated with the transaction, including any allocation formula used to attribute indirect costs; 7. all information necessary to verify compliance with the rules and the accuracy of amounts stated, i.e. invoices, vouchers, communications, journal entries, workpapers, information supporting the price of each transaction, including but not

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SUBJECT	REQUIREMENT
	limited to the cost and allocation method of the transaction and when the cost was the result of a competitive bidding process, the market price and basis for the market price; 8. be summarized and filed with the Commission as part of the annual report. Unless otherwise ordered by the Commission, a copy of FERC Form 60, Annual Report of Centralized Service Companies, may be filed.
	Each public utility shall file contemporaneously with its annual report a summary report indicating the aggregate dollar amount of all transactions described in Rule III.G.(1), (2), (3), and (4) which the utility has conducted with each utility, including the name of each such affiliate.
	Each public utility is to maintain, update annually, train its employees in, and (within 120 days following the effectiveness of these rules, and thereafter, to the extent of material changes, in each annual report) file with the Commission, written

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SUBJECT	REQUIREMENT
	procedures which ensure compliance with the rules, such procedures shall include, at a minimum: a. all internal rules, practices, financial record keeping requirements, and other policies governing affiliate transactions among or between the public utility and its affiliates; b. the names and addresses of all the public utility's affiliates; c. an organizational chart depicting the ownership relationships between the public utility and those affiliates that participate in affiliate transactions with the public utility; d. a description of the types of assets, goods and services provided in any existing affiliate transaction lasting more than one year; and e. a cost allocation manual or other description of the method used to determine compensation in affiliate transactions
Commission Access	The Commission shall have access to all books and records of a public utility and its affiliate to the extent such access is relevant to determining

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SUBJECT	REQUIREMENT
	compliance with all applicable Arkansas statutes and rules or establishing rates subject to the Commission's jurisdiction.

ALLOCATION OF COSTS AND REVENUES

The Commission's rules for the allocation of certain costs and revenues related to affiliate transactions are provided in the table below:

SUBJECT	REQUIREMENTS
Affiliate Financial Transactions Rule IV	Except as provided otherwise in the Rules or in other applicable law, a public utility shall not engage in any affiliate transaction in which the public utility: 1. provides to or shares with any affiliate any financial resource or financial benefit, including, but not limited to any loan, extension of credit, guarantee or assumption of debt, indemnification, pledge of collateral; or encumbrance of or restriction on the disposition of any public utility; or 2. incurs any debt for purposes of investing in, or otherwise supporting, any business other than the provision of public utility service in Arkansas.

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SUBJECT	REQUIREMENTS
	A public utility may obtain financial resources from an affiliate for public utility purposes, provided that the cost to the public utility of such financial resource does not exceed the lower of market price or the affiliate's fully allocated cost.
	This part of the rule shall not apply to or prohibit any of the following unless the Commission finds, after notice and hearing, unless waived by the parties, and consistent with applicable law, that the arrangement is not consistent with the purposes of the rules: 1. An inter-affiliate financial transaction integral to an affiliate transaction for goods or services to and consistent with Rule V (Affiliate Transactions Other than Financial Transactions); 2. Payment of dividends by a public utility to affiliates that own stock in such public utility; 3. Transactions in connection with the factoring of accounts receivable, the creation and use of special purpose financing entities, and the

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	creation and use of money pool or cash management arrangements, subject to safeguards to prevent cross-subsidization and unauthorized pledges or encumbrances of public utility assets; 4. Any loan, extension of credit, guarantee, assumption of debt, restriction on disposition of assets, indemnification, investment, or pledge of assets by public utility for the purpose of supporting the utility related business activities of an affiliate; 5. Any debt incurred by a public utility, including debt that imposes any encumbrance on, or any restriction placed on the disposition of any assets of, the public utility for the purpose of supporting the utility related business activities of an affiliate; 6. Receipt by a public utility of capital contributions or proceeds from the sale of common stock to its parent holding company; 7. Receipt by a public

SUBJECT	REQUIREMENTS
	utility of financial resources from an affiliate for any non-public utility purpose, provided that the cost to the public utility of such resources shall not be recovered from the public utility's customers in Arkansas; 8. Any financing arrangement involving a public utility and any affiliate that was in existence as of the effective date of the rules; provided that the public utility files with the Commission a description of each such arrangement involving a public utility and any affiliate having an annual value or amount in excess of $350,000 and such filing is received within 120 days of the effective date of the rules; 9. Any other affiliate transaction proposed by a public utility, provided that the public utility first files with the Commission an application for approval of such proposed affiliate financial transaction including a detailed description thereof and any relevant supporting

SUBJECT	REQUIREMENTS
	documentation, and the Commission finds, after notice and hearing, unless waived by the partied, on such application, that the proposed affiliate financial transaction is consistent with the purposes of the rules.
Affiliate Transactions other than Financial Transactions Rule V	With respect to an affiliate transaction involving assets, goods, services, information having competitive value, or personnel, a public utility shall not: 1. receive anything of value, unless the compensation paid by the public utility does not exceed the lower of market price of fully allocated cost of the item received; and, 2. provide anything of value, unless the compensation received by the public utility is no less than the higher of market price or fully allocated cost of the item provided.
	This rule shall not apply to: 1. exchanges of information (a)necessary to the reliable provision of public utility service by a public utility, provided such exchange occurs consistently with guidelines published by

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	the utility and applied equally to affiliates and non-affiliates; (b) required by or necessary to comply with federal statutes or regulations; or (c)between or among a public utility, its parent holding company, a service company and any affiliated rate-regulated utility in another State. 2. The provision of shared corporate support services, at fully allocated cost, between or among a public utility and any affiliate, including a service company. 3. The provision, at fully allocated cost, of assets, goods, services, or personnel between or among a public utility and a affiliated rate-regulated utility in another State. 4.The provision of assets, goods, services, information having competitive value, or personnel, at a price determined by competitive bidding or pursuant to a regulatory filed or approved tariff or contract. 5. Any other affiliate transaction proposed by a public utility to be exempted from the rule provided that the public utility first

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	files with the Commssion an application for an exemption of such proposed affiliate transaction from the requirements of the rule, including a detailed description of the proposed transaction and any relevant supporting documentation, and the Commission finds, after notice and hearing, that the exemption is consistent with the purposes of the rules.

COMPLIANCE REQUIRIEMENTS

The Commission’s compliance requirements applicable to the affiliate transactions are provided in the table below:

SUBJECT	REQUIREMENT
Annual Certification	No later than June 1 of each year, each public utility shall file with the Commission a notice, signed by both the public utility’s president or chief executive officer and its chief financial offices, certifying the public utility’s compliance with these rules in the prior year; and other annual information and reports required under the rules.
	The Commission may at any time initiate a proceeding against a public utility to determine whether a reasonable basis exists that

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	the public utility is out of compliance with the rules. If the Commission, after notice and hearing, makes such determination, the Commission may require the public utility to engage an independent accountant (which, at the public utility's election, may be the accountant that regularly audits the public utility's financial statements) to conduct Agreed Upon Procedures to review identified accounting entries, methods or procedures used by the public utility in connection with these rules. A work plan outlining such Agreed Upon Procedures, together with such letters or acknowledgements as shall be reasonably required by the accountant in connection with such engagement, shall be developed by the public utility and filed with the Commission for approval. Upon review of the information provided by such independent accountant after undertaking, the Commission may order the public utility to make changes in its accounting methods or procedures found by the Commission in to be reasonably necessary to ensure future compliance with these Rules.

OTHER REQUIREMENTS – Additional requirements applicable to affiliate transactions are provided in the table below:

SUBJECT	***REQUIREMENT***
Bond Rating Downgrades Rule VII	This rule applies to any public utility that has a separate, stand-alone bond rating by Standard and Poor's or Moody's, and that has affiliates, other than utility related businesses, with assets whose total book value exceeds ten percent of the book value of the public utility's assets. If a public utility's bond ratings are downgraded to a Standard and Poor's rating of BB+ or lower, or to a Moody's rating of Ba1 or lower, such utility shall notify the Commission within 30 days of such downgrading. The public utility will provide the Commission a copy of publicly released information about such rating downgrade and such other information as the Commission requests. If the Commission finds, after notice and opportunity for hearing, that the public utility's downgrade would not have occurred but for one or more relationships between such public utility and one or more affiliates, then the

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	Commission may impose remedies designed to insulate the public utility and its customers from any diminution in the public utility's ability to carry out its obligation to serve at reasonable rates.
Utility Ownership of Non-utility Business Rule VIII	A public utility shall not engage in a non-utility business other than a utility related business if the total book value of the non-utility assets owned by the utility exceeds 10 percent of the book value of the total assets of the public utility and all its affiliates. This rule does not apply to or prohibit a public utility or any affiliate thereof from continuing to engage in any non-utility business existing as of the effective date of these rules; provided the public utility files with the commission a description of such non-utility business existing as of the effective date of these rules and such filing is received within 120 days of the effective date of these rules. Each public utility or its public utility holding company shall file an annual report with the Commission in accordance with the rules that includes: 1. a certification by the president of the public

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	utility that the public utility is in compliance with this section ;and 2. all financial information necessary for the Commission to determine the utility is complying with the requirements of the rules.
EXEMPTIONS Rule XI	Any utility may petition for exemption from any of the rules on the basis that application of the rule would not be in the public interest. Any existing financial arrangements, provision of corporate services or other affiliate relationship which could be deemed to be in violation of these rules will be allowed to continue for a period of one year from adoption of these rules in order to allow the utilities involved to seek an exemption from the application of these rules for those existing circumstances
MISCELLANEOUS Rule X	The costs of any affiliate transaction found to be inconsistent with these rules shall be adjusted in a ratemaking proceeding to be consistent with these rules.

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INDIANA RULES AND REQUIREMENTS

SUMMARY

Indiana's rules and requirements applicable to cost allocations and affiliate transactions can be found in the Indiana Code and in the Indiana Utility Regulatory Commission's (the IURC's, or the Commission's) order, dated April 26, 1999, in Cause No. 41210, including the Stipulation and Settlement Agreement which is attached to the order as Exhibit A, as well as other orders of the Commission.

Cause No. 41210 covers the IURC's investigation of the proposed merger of American Electric Power Company, Inc. and Central and South West Corporation. Section 8 of the Stipulation and Settlement Agreement provides for Affiliate Standards between the regulated and non-regulated affiliates of the merged company.

DOCUMENTATION REQUIREMENTS

The IURC's documentation requirements for affiliate transactions are captured in the following table:

SUBJECT	***REQUIREMENT***
Separate Books and Records	Each AEP Operating Company shall maintain, in accordance with generally accepted accounting principles, books, records and accounts that are separate from the books, records and accounts of its affiliates, consistent with Part 101 – Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act. [Section 8.B.]
Cost Allocation	An AEP operating company which provides both

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INDIANA RULES AND REQUIREMENTS

SUBJECT	***REQUIREMENT***
Documentation	regulated and non-regulated services or products, or an affiliate which provides services or products to an AEP operating company, shall maintain documentation in the form of written agreements, an organization chart of AEP (depicting all affiliates and AEP operating companies), accounting bulletins, procedure and work order manuals, or other related documents, which describe how costs are allocated between regulated and non-regulated services or products.[Section 8.P.]
Employee Movements	AEP shall document all employee movement between and among all affiliates. Such information shall be made available to the IURC and consumer advocate upon request. [Section 8. G.]
Itemized Billing Statements Itemized Billing	Any untariffed, non-utility service provided by an AEP operating company or affiliated service company to any affiliate shall be itemized in a billing statement pursuant to a written contract or written arrangement. The AEP operating company and any affiliated service company shall maintain and keep available for inspection by the Commission copies of each billing statement,

SUBJECT	***REQUIREMENT***
Statements (Cont'd)	contract and arrangement between the AEP operating company or affiliated service company and its affiliates that relate to the provision of such untariffed non-utility services. [Section 8.E.] Goods and services provided by a non-utility affiliate to an AEP operating company shall be by itemized billing statement pursuant to a written contract or written arrangement. The operating company and non-utility affiliate shall maintain and keep available for inspection by the Commission copies of each billing statement, contract and arrangement between the operating company and its non-utility affiliates that relate to the provision of such goods and services in accordance with the Commission's applicable retention requirements. [Section 8.F.]

[Source: Stipulation and Settlement Agreement in Cause No. 41210]

TRANSFER PRICING

Transactions between the regulated electric utility and its affiliates shall adhere to the affiliate standards included in the following table:

SUBJECT	***REQUIREMENT***

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INDIANA RULES AND REQUIREMENTS

SUBJECT	***REQUIREMENT***
Guiding Principles	The financial policies and guidelines for transactions between the regulated utility and its affiliates shall reflect the following principles: 1. An AEP operating company's retail customers shall not subsidize the activities of the operating company's non-utility affiliates or its utility affiliates. [Section 8.A.1.] 2. An AEP operating company's costs for jurisdictional rate purposes shall reflect only those costs attributable to its jurisdictional customers. [Section 8.A.2.] 3. These principles shall be applied to avoid costs found to be just and reasonable for ratemaking purposes by the Commission being left unallocated or stranded between various regulatory jurisdictions, resulting in the failure of the opportunity for timely recovery of such costs by the operating company and/or its utility affiliates; provided, however, that
Guiding	

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INDIANA RULES AND REQUIREMENTS

SUBJECT	***REQUIREMENT***
Principles (Cont'd)	no more than one hundred percent of such cost shall be allocated on an aggregate basis to the various jurisdictions. [Section 8.A.3.] 4. An AEP operating company shall maintain and utilize accounting systems and records that identify and appropriately allocate costs between the operating company and its affiliates, consistent with these cross-subsidization principles and such financial policies and guidelines. [Section 8.A.4.]
Asset Transfers	Asset transfers between an AEP operating company and a non-utility affiliate shall be at fully distributed costs in accordance with current SEC issued requirements or other statutory requirements if the SEC has no jurisdiction. [Section 8.C.]

[Source: Stipulation and Settlement Agreement in Cause No. 41210]

REPORTING REQUIREMENTS

The Stipulation and Settlement Agreement in Cause No. 41210 provides in part that the IURC may establish reporting requirements regarding the nature of inter-company transactions concerning the operating company and a description of the basis upon which cost allocations and transfer pricing have been established in these transactions. [Section 8.W.]

AUDIT REQUIREMENTS

According to the provisions of the Stipulation and Settlement Agreement, an AEP operating company shall record all transactions with its affiliates, whether direct or indirect. Also, an AEP operating company and its affiliates shall maintain sufficient records to allow for an audit of the transactions involving the operating company and its affiliates. [Section 8.C.]

Furthermore, AEP shall contract with an independent auditor who shall conduct biennial audits for eight years after merger consummation of affiliated transactions to determine compliance with the affiliate standards contained in the Stipulation and Settlement Agreement. The results of such audits shall be filed with the Commission. [Section 8.V.]

Prior to the initial audit, AEP will conduct an informational meeting with the Commission regarding how its affiliates and affiliate transactions will or have changed as a result of the merger. [Section 8.V.]

The Stipulation and Settlement Agreement approved by the Commission in Cause No. 41094 states that I&M may be subject, no more than once annually, to an independent audit of all matters deemed relevant to retail rates and which relate, directly, or indirectly to transactions or [asset] transfers between I&M and AEPC.

OTHER REQUIREMENTS

The Stipulation and Settlement Agreement contains other requirements related to affiliate transactions some of which are listed here:

- Thirty days prior to filing any affiliate contract (including service agreements) with the Securities and Exchange Commission or the Federal Energy Regulatory Commission the AEP operating company shall submit to the Commission a copy of the proposed filing. [Section 8. T.]
- AEP will provide the Commission with notice at least 30 days prior to any filings that propose new allocation factors with the SEC. [Section 6]
- AEP shall designate an employee who will act as a contact for the Commission and consumer advocates seeking data and information regarding affiliate transactions and personnel transfers. Such employee shall be responsible for providing data and information requested by the Commission for any and all transactions between the jurisdictional operating company and its affiliates, regardless of which affiliate(s), subsidiary(ies) or associate(s) of the

OTHER REQUIREMENTS (Cont'd)

AEP operating company from which the information is sought. [Section 8.Q.]

The Indiana Code [§8-1-2-49] states, in part, that no management, construction, engineering, or similar contract with any affiliated interest shall be effective unless it shall first have been filed with the Commission. If it is found that any such contract is not in the public interest, the Commission, after investigation and a hearing, is authorized to disapprove the contract.

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KENTUCKY RULES AND REQUIREMENTS

SUMMARY

Kentucky’s rules and requirements applicable to cost allocations and affiliate transactions are contained in Kentucky Revised Statues, (KRS) 278.2201 thru 278.2219; Kentucky Public Service Commission Regulation 807KAR 5:08 and in certain orders of the Kentucky Public Service Commission (the Commission).

CAM REQUIREMENTS

The following table summarizes Kentucky’s Cost Allocation Manual (CAM) requirements:

SUBJECT	***REQUIREMENT***
Summary	Any utility that engages in a non-regulated activity, whose revenue exceeds 2% of the utility’s total revenue or $1,000,000 annually, shall develop and maintain a CAM. [KRS278.2203 (4) (a)]
“CAM” Definition	CAM means a cost allocation manual; that is, an indexed compilation and documentation of a company’s cost allocation policies and related procedures. [KRS 278.010 (20)]
Contents	The CAM shall contain the following information for a utility’s jurisdictional operations in the Commonwealth of Kentucky: (a) A list of regulated and non-regulated divisions within the utility; (b) A list of all regulated and non-regulated affiliates of the utility to which the utility provides services or products and where the

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SUBJECT	REQUIREMENT
Contents (Cont'd)	affiliates provide non-regulated activities as defined in [KRS278.2205 (2) (a) (b)]; (c) A list of services and products provided by the utility, an identification of each as regulated or non-regulated, and the cost allocation method generally applicable to each category; [KRS278.2205 (2) (c)]; (d) A list of incidental, non-regulated activities that are reported as regulated activities in accordance with the provisions pf [LRS278.2205 (2) (d)]; (e) A description of the nature of transactions between the utility and the affiliate; and [KRS278.2205 (2) (e)]; (f) For each FERC account and sub-account, a report that identifies whether the account contains costs attributable to regulated operations and non-regulated operations. The report shall also identify whether the costs are joint costs that cannot be directly identified. A description of the

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SUBJECT	REQUIREMENT
Contents (Cont'd)	methodology used to apportion each of these costs shall be included and the allocation methodology shall be consistent with cost allocation methodologies set out in KRS 278.2203. [KRS278.2205 (2) (f)]
Filing Requirements	Within 270 days of the effective date of July 14, 2000, the utility shall file: (a) A statement with the Commission that certifies the CAM has been developed and will be adopted by management effective with the beginning of the next calendar year. The statement shall be signed by an officer of the utility; and (b) One copy of the CAM. [KRS278.2205 (3) (a)-(b)]
Changes	Within 60 days of any material change in matters required to be listed in the CAM, the utility shall amend the CAM to reflect the change. [KRS278.2205 (4)]
Public Inspection	The CAM shall be available for public inspection at the utility and at the Commission. [KRS278.2205 (5)]
Rate Proceedings	The CAM shall be filed as part of the initial filing requirement in a proceeding involving an application for

SUBJECT	***REQUIREMENT***
Rate Proceedings (Cont'd)	an adjustment in rates pursuant to KRS 278.190. [KRS278.2205(6)]

TRANSFER PRICING

KRS278.2207 thru KRS278.2219 contains very specific instructions on the pricing of assets, services and products transferred between the utility and its affiliates, as captured in the following table:

SUBJECT	***REQUIREMENT***
Summary	A utility shall not subsidize a non-regulated activity provided by an affiliate or by the utility itself. Utilities must keep separate accounts and allocate costs in accordance with procedures established by the Commission. [KRS278.2201]
Pricing Rules	The terms for transactions between a utility and its affiliates shall be in accordance with the following: (a) Services and products provided to an affiliate by the utility pursuant to a tariff shall be at the tariffed rate, with nontariffed items priced at the utility's fully distributed cost but in no event less than market, or in compliance with the utility's existing United States Department of Agriculture (USDA), Securities and Exchange

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SUBJECT	***REQUIREMENT***
Pricing Rules (Cont'd)	Commission (SEC), or Federal Energy Regulatory Commission (FERC) approved cost allocation methodology. [KRS278.2207 (1) (a)] (b) Services and products provided to the utility by an affiliate shall be priced at the affiliate's fully-distributed cost but in no event greater than market or in compliance with the utility's existing USDA, SEC, or FERC approved cost allocation methodology. [KRS278.2207 (1) (6)] *NOTE: A utility may file an application with the commission requesting a deviation from the requirements of this section for a particular transaction or class of transactions. The utility shall have the burden of demonstrating that the requested pricing is reasonable. The commission may grant the deviation if it determines the deviation is in the public interest. Nothing in this section shall be construed to interfere with the commission's requirement to ensure fair, just, and reasonable rates for utility services. [IRS278.2219 92)]*

AFFILIATE TRANSACTION REPORTING REQUIREMENTS	Kentucky Public Service Commission and the Commission's orders in Case Nos. 97-309 and 99-149 contain very specific reporting requirements for affiliate transactions.
Regulation 807KAR5:080	In addition to the CAM reporting requirements established by KRS 278.2201 thru 278.2219 as noted above, PSC Regulation 807 KAR 5:080 requires the utility to inform the Commission of new non-regulated activities begun by itself or by the utility's affiliate within a timeframe to be established by the Commission [KRS278.230 (3)]. Also, the Commission may require the utility to file annual reports of information related to affiliate transactions when necessary to monitor compliance with the transaction guidelines contained in KRS278.2205 [807KAR 5:080 Section 2]
Case 97-309	In Case 97-309 involving the approval of affiliate transactions between KPCO and AEPC (as outlined above), the Commission has ordered KPCO to file an annual report that lists all transactions with AEPC that describes the parties involved, the assets transferred, the services provided and the transaction prices. The report should also specify for each transaction whether the price was based on cost or market and, if market, how the market price was determined.
Case 99-149	The Commission's order in Case No. 99-149, dated June 14, 1999, related to the proposed merger of American Electric Power Company, Inc. (AEP) and Central and South West Corporation established specific reporting requirements for KPCO, its parent company

(i.e., AEP) and related subsidiaries. While the Commission's order in Case No. 99-149 has been superseded by KRS 278.2201 thru KRS278.2219 and Ky PSC Regulation 807KAR5:080, dated July 14, 2000, the periodic reports required by the Commission's June 1999 order remain in effect. The following table provides details of the specific reporting requirements:

SUBJECT	***REQUIREMENT***
Periodic Reports [Case No. 99-149, Page 10]	1. Annual financial statements of AEP should be furnished to the Commission, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. 2. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. 3. The financial statements for any non-consolidated subsidiaries of AEP should be furnished.
Annual Reports [Case No. 99-149, Page 11 ¶1,2]	1. A general description of the nature of inter-company transactions shall be provided with specific identification of major transactions,

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SUBJECT	***REQUIREMENT***
Annual Reports [Case No. 99-149, Page 11 ¶1,2] (Cont'd)	and a description of the basis upon which cost allocations and transfer pricing have been established. This report should discuss the use of the cost or market standard for the sale or transfer of assets, the allocation factors used, and the procedures used to determine these factors if they are different from the procedures used in prior years. 2. A report that identifies professional personnel transferred from KPCO to AEP or any of its non-utility subsidiaries shall be provided to the Commission. This report should include a description of the duties performed by the employee while employed by KPCO and to be performed subsequent to transfer. 3. AEP should file on an annual basis a report detailing KPCO's proportionate share of AEP's total operating revenues, operating and maintenance expenses, and number of employees.
Special Reports [Case No. 99-149,	1. AEP should file any contracts or other agreements concerning the

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Pages 11-12]	transfer of utility assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. 2. AEP should also file the following special reports: • An annual report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. • An annual report containing years of service at KPCO and the salaries of professional employees transferred from KPCo to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. • An annual report of cost allocation factors in use, supplemented upon significant change. • Summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation effect. • An annual report of methods used to update

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	or revise the cost allocation factors in use, supplemented upon significant change.
Use of Existing Reports [Case No. 99-149, Page 12 ¶7]	Where the same information sought in the above noted reports has been filed with the SEC, FERC, or another state regulatory commission, AEP may provide copies of those filings rather than prepare separate reports.

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LOUISIANA RULES AND REQUIREMENTS

SUMMARY

Louisiana's requirements applicable to cost allocations and affiliate transactions are contained in the Affiliate Transaction Conditions that appear in Appendix A to the Louisiana Public Service Commission's (the Commission's) Order No. U-23327, dated September 16, 1999, in the matter of the proposed merger of American Electric Power Company, Inc. (AEP) and Central and South West Corporation.

DOCUMENTATION REQUIREMENTS

The Commission's documentation requirements applicable to affiliate transactions, as contained in the Affiliate Transaction Conditions, are captured in the following table:

SUBJECT	***REQUIREMENT***
Access to Books and Records	AEP and Southwestern Electric Power Company (SWEPCO, and the Company) will provide the Commission access to their books and records, and to any records of their subsidiaries and affiliates that reasonably relate to regulatory concerns and that affect SWEPCO's cost of service and/or revenue requirement. [¶ 2]
Service Company Costs	For ratemaking and regulatory reporting purposes, SWEPCO shall reflect the costs assigned or allocated from affiliate service companies on the same basis as if SWEPCO had incurred the costs directly. This condition shall not apply to book accounting for affiliate transactions. [¶ 11]

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ALLOCATION OF COSTS

The Commission's requirements for the allocation of certain costs and revenues, as contained in the Affiliate Transaction Conditions, are presented in the following table:

SUBJECT	***REQUIREMENT***
Notification of Changes in Cost Allocation Methodologies	The Company shall submit in writing to the Commission any changes it proposes to the System Agreement, the System Integration Agreement and any other affiliate cost allocation agreements or methodologies that affect the allocation or assignment of costs to SWEPCO. The written submission to the Commission shall include a description of the changes, the reasons for such changes, and an estimate of the impact, on an annual basis, of such changes on SWEPCO's regulated costs. To the extent that any such changes are filed with the SEC or FERC, the Company agrees to utilize its best efforts to notify the Commission at least 30 days prior to those filings and at least 90 days prior to the proposed effective date of those changes or as early as reasonably practicable, to allow the Commission a timely opportunity to respond to such filings. If the documents to be filed with the SEC or FERC are not

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SUBJECT	***REQUIREMENT***
Notification of Changes in Cost Allocation Methodologies (Cont'd)	finalized 30 days prior to the filing, the information required above may be provided by letter to the Commission with a copy of the SEC or FERC filing to be provided as it is prepared. The filing by the Company of this information with the Commission shall not constitute acceptance of the proposed changes, the allocation or assignment methodologies, or the quantifications for ratemaking purposes. [¶ 12]
Revenue Allocation Applicable to Product or Service Development	If an unregulated business markets a product or service that was developed by SWEPCO or paid for by SWEPCO directly or through an affiliate, and the product or service is actually used by SWEPCO, all profits on the sale of such product or service (based on Louisiana retail jurisdiction) shall be split evenly between SWEPCO, which was responsible for or shared the cost or developing the product, and the unregulated business responsible for marketing the product or service to third parties, after deducting all incremental costs associated with making such product or service available for sale, including the direct cost of marketing such product or

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SUBJECT	***REQUIREMENT***
Revenue Allocation Applicable to Product or Service Development (Cont'd)	service. However, in the event that such product or service developed by SWEPCO to be used in its utility business is not actually so used, and subsequently is marketed by the unregulated business to third parties, SWEPCO shall be entitled to recover all of its costs to develop such product or service before any such net profits derived from its marketing shall be so divided. If SWEPCO jointly develops such product or service and shares the development with other entities, then the profits to be so divided shall be SWEPCO's *pro rata* share of such net profits based on SWEPCO's contribution to the development costs. [¶ 14]

TRANSFER PRICING

The Commission's transfer pricing requirements for affiliate transactions, as contained in the Affiliate Transaction Conditions, are presented in the following table:

SUBJECT	***REQUIREMENT***
Asset Transfers	**Purchases.** Assets with a net book value in excess of $1 million per transaction, purchased by or transferred to the regulated electric utility (SWEPCO) from an unregulated affiliate either directly or indirectly (through another affiliate),

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SUBJECT	***REQUIREMENT***
Asset Transfers (Cont'd)	must be valued for purposes of the Louisiana retail rate base (but not necessarily for book accounting purposes) at the lesser of the cost to the originating entity and the affiliated group (CSW or AEP) or the fair market value, unless otherwise authorized by applicable Commission rules, orders, or other Commission requirements. [¶ 4.a.] **Sales.** Assets with a net book value in excess of $1 million per transaction, sold by or transferred from the regulated electric utility (SWEPCO) to an unregulated affiliate either directly or indirectly (through another affiliate), with the exception of accounts receivable sold by SWEPCO to AEP Credit Inc., must be valued for purposes of the Louisiana retail rate base (but not necessarily for book accounting purposes) at the greater of the cost to SWEPCO or the fair market value, unless otherwise authorized by applicable Commission rules, Orders, or other Commission requirements. [¶ 4.b.] **Reporting.** The Company shall notify the Commission in writing at least 90 days in

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SUBJECT	***REQUIREMENT***
Asset Transfers (Cont'd)	advance of a proposed purchase, sale or transfer of assets with a net book value in excess of $1 million if such proposed purchase, sale or transfer is expected at least 90 days before the anticipated effective date of the transaction. With the notice, the Company shall provide such information as may be necessary to enable the Commission Staff to review the proposed transaction, including, without limitation, the identity of the asset to be transferred, the proposed transferor and transferee, the value at which the asset will be transferred, the net book value of the asset, and the anticipated effect on Louisiana retail customers. When such a transaction requires approval of a federal agency, under no circumstances shall such notification be less than 60 days in advance or such longer advance period as the applicable federal agency from time to time prescribe. If not provided with the initial notice, the Company will provide the Commission with a copy of its federal filing at the same time it is submitted to the federal agency. [¶ 6]

SUBJECT	***REQUIREMENT***
Asset Transfers (Cont'd)	**Burden of proof.** Consistent with Commission and legal precedents and Commission General Orders, the Company shall have the burden of proof in any subsequent ratemaking proceeding to demonstrate that such purchase, sale or transfer of assets satisfies the requirements of applicable Commission and legal precedent and Commission General Orders, and will not harm the ratepayers. [¶ 7] **Treatment of gains or losses.** The Commission reserves the right, in accordance with Commission and legal precedents and Commission General orders, to determine the ratemaking treatment of any gains or losses from the sale or transfer of assets to affiliates. [¶ 8]
Goods and Services	**Purchases.** With the exception of transactions between SWEPCO and AEP Credit Inc. and AEPSC, for goods and services, including lease costs, purchased by SWEPCO from unregulated affiliates either directly or indirectly (through another affiliate), SWEPCO agrees that it will reflect the lower of cost or fair market value in operating expenses for ratemaking purposes, unless otherwise authorized by

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SUBJECT	***REQUIREMENT***
Goods and Services (Cont'd)	applicable Commission rules, Orders, or other Commission requirements. [¶ 10] **Sales.** For goods and services, including lease costs, sold by SWEPCO to unregulated affiliates either directly or indirectly (through another affiliate), SWEPCO agrees that it will reflect the higher of cost or fair value in operating income (or as an offset to operating expenses) for ratemaking purposes, unless otherwise authorized by applicable Commission rules, Orders, or other Commission requirements (e.g., Commission-approved tariffed rates). [¶ 9]

REPORTING REQUIREMENTS

The Commission has not established periodic reporting requirements relative to affiliate transactions other than those noted above in connection with the notification of changes in cost allocation methodologies and asset transfers.

AUDIT REQUIREMENTS

The Commission's audit requirements applicable to affiliate transactions, as contained in the Affiliate Transaction Conditions, are captured in the following table:

SUJECT	***REQUIREMENT***
Audits of Affiliate Transactions	AEP will cooperate with audits ordered by the Commission of affiliate transactions between SWEPCO and other AEP affiliates,

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SUJECT	***REQUIREMENT***
Audits of Affiliate Transactions (Cont'd)	including timely access to the books and records and to persons knowledgeable regarding affiliate transactions, and will authorize and utilize its best efforts to obtain cooperation from its external Auditor to make available the audit workpapers covering areas that affect the costs and pricing of affiliate transactions. [¶ 3]

OTHER REQUIREMENTS

Other requirements of the Commission applicable to affiliate transactions, as contained in the Affiliate Transaction Conditions, are presented in the following table:

SUBJECT	***REQUIREMENT***
Competitive Bidding	SWEPCO or AEPSC on behalf of SWEPCO may not make any non-emergency procurement in excess of $1 million per transaction from an unregulated affiliate other than from AEPSC except through a competitive bidding process or as otherwise authorized by the Commission. Transactions involving the Company and CSW Credit, Inc. (or its successor) for the financing of accounts receivables are exempt from this condition. Records of all such affiliate trans-actions must be maintained until the Company's next

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SUBJECT	***REQUIREMENT***
Competitive Bidding Cont'd)	comprehensive retail rate review. In addition, at the time of the next comprehensive rate review, all such transactions that were not competitively bid shall be separately identified for the Commission by the Company. This identification shall include all transactions between the Company and AEPSC in which AEPSC acquired the goods or services from another unregulated affiliate. [¶ 13]
Mandating of Retail Access by the Commission	If retail access for SWEPCO-La. is mandated by the Commission, or through action by the Federal Energy Regulatory Commission or federal legislation, then SWEPCO-La. shall have the right to petition the Commission for modification to the terms of this merger settlement, including the affiliate transaction conditions, that are made necessary by the mandating of retail access and its likely impact on the retail rates at SWEPCO-La. Any such petition must establish the necessity of the proposed modifications and provide appropriate protections to ensure that the benefits of this merger are preserved for SWEPCO-La. regulated customers, including merger savings and the hold harmless provisions

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SUBJECT	***REQUIREMENT***
Mandating of Retail Access by the Commission (Cont'd)	set forth herein. The Commission will act upon the petition in accordance with its normal rules and procedures. This paragraph is not intended to limit SWEPCO's right to petition the Commission in the event that electric utility unbundling or retail access is ordered by a state commission regulating SWEPCO's retail rates, provided that SWEPCO must comply with the requirements set forth above in any such petition. [¶ 17]

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SUMMARY

Michigan's rules and requirements applicable to cost allocations and affiliate transactions are included in various orders of the Michigan Public Service Commission (the MPSC, or the Commission).

DOCUMENTATION REQUIREMENTS

The MPSC's documentation requirements for affiliate transactions and cost allocations can be found in the Settlement Agreement approved by the Commission in its Opinion and Order in Case No. U-12204 in the matter of the proposed merger of American Electric Power Company, Inc. and Central and South West Corporation, and its Code of Conduct for electric utilities and alternative electric suppliers (Opinion and Order, dated December 4, 2000, in Case No.U-12134) with Redline changes to October 29, 2001 Final Version. The term "alternative electric suppliers" is defined in MCL 460.10.g, MSA 22.13(10g).

The documentation requirements found in the Settlement Agreement document are captured in the following table:

SUBJECT	***REQUIREMENT***
Separate Books and Records	Each AEP Operating Company shall maintain, in accordance with generally accepted accounting principles, books, records and accounts that are separate from the books, records and accounts of its affiliates, consistent with Part 101 – Uniform System of Accounts prescribed for Public Utilities and Licensees subject to the provisions of the Federal Power Act, [Section 8.B.]

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SUBJECT	***REQUIREMENT***
Cost Allocation Documentation	An AEP operating company which provides both regulated and non-regulated services or products, or an affiliate which provides services or products to an AEP operating company, shall maintain documentation in the form of written agreements, an organization chart of AEP (depicting all affiliates and AEP operating companies), accounting bulletins, procedure and work order manuals, or other related documents, which describe how costs are allocated between regulated and non-regulated services or products. [Section 8.P.]
Employee Movements	AEP shall document all employee movement between and among all affiliates. Such information shall be made available to the Commission upon request. [Section 8.G.]
Itemized Billing Statements	Any untariffed, non-utility service provided by an AEP operating company or affiliate service company to any affiliate shall be itemized in a billing statement pursuant to written contract or written arrangement. The AEP operating company and any affiliated service company shall maintain and keep available for inspection by the Commission copies of

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SUBJECT	***REQUIREMENT***
Itemized Billing Statements (cont'd)	each billing statement, contract and arrangement between the AEP operating company or affiliated service company and its affiliates that relate to the provision of such untariffed non-utility services. [Section 8.E.] Goods and services provided by a non-utility affiliate to an AEP operating company shall be by itemized billing statement pursuant to a written contract or written arrangement. The operating company and non-utility affiliate shall maintain and keep available for inspection by the Commission copies of each billing statement, contract and arrangement between the operating company and its non-utility affiliates that relate to the provision of such goods and services in accordance with applicable Commission retention requirements. [Section 8.F.]

Code of Conduct

The documentation requirements found in the MPSC's Code of Conduct document are captured in the following table:

SUBJECT	***REQUIREMENT***
Separate Books and Records	An electric utility or alternative electric supplier shall maintain its

SUBJECT	REQUIREMENT
Separate Books and Records (Cont'd)	books and records separately from those of its affiliates or other entities within its corporate structure. [§ II.C.]

TRANSFER PRICING

The MPSC's transfer pricing requirements can be found in the Settlement Agreement document, it's Code of Conduct for electric utilities and alternative electric suppliers, and the Company's Code of Conduct compliance plan on file with the Commission.

SETTLEMENT AGREEMENT

The transfer pricing and related requirements contained in the Settlement Agreement document are captured in the following table:

SUBJECT	REQUIREMENT
Guiding Principles Guiding Principles	The financial policies and guidelines for transactions between the regulated utility and its affiliates shall reflect the following principles: 1. An AEP operating company's retail customers shall not subsidize the activities of the operating company's non-utility affiliates or its utility affiliates. [Section 8.A.1.] 2. An AEP operating company's costs for jurisdictional rate purposes shall reflect only those costs attributable to its

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SUBJECT	***REQUIREMENT***
(Cont'd) Guiding Principles	jurisdictional customers. [Section 8.A.2.] 3. An objective of these principles shall be to avoid costs found to be just and reasonable for ratemaking purposes by the Commission being left unallocated or stranded between various regulatory jurisdictions, resulting in the failure of the opportunity for timely recovery of such costs by the operating company and/or its utility affiliates; provided, however, that no more than one hundred percent of such costs shall be allocated on an aggregate basis to the various regulatory jurisdictions. [8.A.3.] 4. An AEP operating company shall maintain and utilize accounting systems and records that identify and appropriately allocate costs between the operating company and its affiliates, consistent with these cross-subsidization

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SUBJECT	REQUIREMENT
(Cont'd)	principles and such financial policies and guidelines. [Section 8.A.4.]

Code of Conduct

The transfer pricing requirements contained in the MPSC's Code of Conduct document are captured in the following table:

SUBJECT	REQUIREMENT
Preferential Treatment	An electric utility or alternative electric supplier that offers, itself or through its affiliates, both regulated and unregulated service shall not provide any affiliate or other entity within its corporate structure, or any customer of an affiliate or other entity within its corporate structure, preferential treatment or any other advantages that are not offered under the same terms and conditions and contemporaneously to other suppliers offering services or products within the same service territory or to customers of those suppliers. This provision includes, but is not limited to, all aspects of the electric utility's or alternative electric supplier's service, includ-ing pricing, responsiveness to requests for service or repair, the availability of firm and interruptible
Preferential Treatment	

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(Cont'd)	service, and metering requirements (emphasis added). [§ III. A.]
Discounts, Rebates, and Waivers	If an electric utility provides to any affiliate or other separate entity, or customers of an affiliate or other separate entity within its corporate structure, a discount, rebate, fee waiver, or waiver of its regulated tariffed terms and conditions for services or products, it shall contemporaneously offer the same discount, rebate, fee waiver, or waiver [of its regulated tariffed terms and conditions] to all alternative electric suppliers operating within the electric utility's service territory or all alternative electric supplier's customers. [§ III. B.]
Services, Products, or Property Services, Products, or	If an electric utility or alternative electric supplier provides services, products or property to any affiliate or other entity within the corporate structure, compensation shall be based upon the higher of fully allocated cost or market price. If an affiliate or other entity within the corporate structure provides services, products, or property to an electric utility or alternative electric

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Property (Cont'd)	supplier, compensation shall be based upon the lower of fully allocated cost or market-price [§ III. C.] In the Michigan Code of Conduct Compliance Plan filed March 11, 2002 in Case No. U-12134, I&M, d/b/a AEP, made the following note: Note: Section 13 of the Public Utility Holding Company Act of 1935, as amended (PUHCA), and the rules (particularly Rules 90 and 91) and orders of the SEC currently require that transactions between associated companies in a registered holding company system be performed at cost with limited exceptions. Over the years, the AEP System has developed numerous affiliated services, sales and construction relationships and, in some cases, invested significant capital and developed significant operations in reliance upon the ability to recover its full costs under these provisions.

REPORTING REQUIREMENTS

The Settlement Agreement in Case No. U-12204 provides in part that the Commission may establish reporting requirements regarding the nature of intercompany transactions concerning the operating company and a description of the basis upon which cost allocations and transfer pricing have been established in these transactions. [Section 8.W.]

Code of Conduct

The MPSC's Code of Conduct for electric utilities and alternative electric suppliers also includes a reporting requirement applicable to transferred employees. In this instance, the reporting frequency is semi-annually. The Code of Conduct reporting requirement is captured in the following table:

SUBJECT	***REQUIREMENT***
Finance	An electric utility or alternative electric supplier shall not finance or co-sign loans for affiliates. [§II. F.]
Employee Transfers Employee Transfers (Cont'd)	An electric utility may transfer employees between the utility and any of its affiliates or other entities within the corporate structure as long as the electric utility documents those transfers and files semi-annually with the Commission a report of each occasion on which an employee of the electric utility became an employee of an affiliate or other entity within its corporate structure and/or an employee of an affiliate or other entity within its

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SUBJECT	***REQUIREMENT***
	corporate structure became an employee of the electric utility. [§ II. G.]

AUDIT REQUIREMENTS

Also according to the provisions of the Stipulation and Settlement Agreement, an AEP operating company shall record all transactions with its affiliates, whether direct or indirect. Also, an AEP operating company and its affiliates shall maintain sufficient records to allow for an audit of the transactions involving the operating company and its affiliates. [Section 8.C.]

Furthermore, AEP shall contract with an independent auditor who shall conduct biennial audits for eight years after merger consummation of affiliated transactions to determine compliance with the affiliate standards contained in the Stipulation and Settlement Agreement. The results of such audits shall be filed with the Commission. [Section 8.V.]

Prior to the initial audit, AEP will conduct an informational meeting with the Commission regarding how its affiliates and affiliate transactions will or have changed as a result of the merger. [Section 8.V.]

OTHER REQUIREMENTS

The MPSC's Code of Conduct for electric utilities and alternative electric suppliers states that an electric utility's or alternative electric supplier's regulated services shall not subsidize in any manner, directly or indirectly, the business of its affiliates or other separate entities (§ II. B.). AEP's cost allocation policies and procedures are consistent with Michigan's requirements relative to cross-subsidization.

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OHIO RULES AND REQUIREMENTS

SUMMARY

Ohio’s requirements applicable to cost allocations and affiliate transactions are, for the most part, captured in the corporate separation rule adopted by the Public Utilities Commission of Ohio (the PUCO, or the Commission) in Case No. 99-1141-EL-ORD as amended in Case Nos. 04-48-El- ORD and 08-777-EL-ORD, and in the regulations and orders of the PUCO.

CAM REQUIREMENTS

The following table details the Commission’s Cost Allocation Manual (CAM) requirements:

SUBJECT	***REQUIREMENT***
Summary	Each electric utility’s affiliate, which provides products and/or services to the electric utility, and/or receives products and/or services from the electric utility, shall maintain information in the CAM, documenting how costs are allocated between the affiliates and its regulated and non-regulated operations. [Source: 4901:1-37-08(A)]
Maintenance	The CAM will be maintained by the electric utility. [Source: 4901:1-37-08(B)]
Assurances	The CAM is intended to ensure the commission that no cross-subsidization is occurring between the electric utility and its affiliates. [Source: 4901:1-37-08(C)]
Contents Contents	The CAM will include: (1) An organization chart of the holding company, depicting all affiliates, as well as a description of activities in which

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SUBJECT	***REQUIREMENT***
(Cont'd)	the affiliates are involved. (2) A description of all assets, services, and products provided to and from the electric utility and its affiliates. (3) All documentation including written agreements, accounting bulletins, procedures, work order manuals, or related documents, which govern how costs are allocated between affiliates. (4) A copy of the job description of each shared employee. (5) A list of names and job summaries for shared consultants and shared independent contractors. (6) A copy of all transferred employees' (from the electric utility to an affiliate or vice versa) previous and new job description. (7) A log detailing each instance in which the electric utility exercised discretion in the application of its tariff provisions. (8) A log of all complaints brought to the utility regarding this chapter. (9) A copy of the minutes of each board of directors

SUBJECT	***REQUIREMENT***
	meeting, where it shall be maintained for a minimum of three years.
Method for Charging Costs	The method for charging costs and transferring assets shall be based on fully allocated costs. [Source: 4901:1-37-08 (E)]
Audit Trail	The costs shall be traceable to the books of the applicable entity. [Source: 4901:1-37-08(F)]
Record Retention Requirements	The electric utility and affiliates shall maintain all underlying affiliate transaction information for a minimum of three years. [Source: 4901:1-37-08 (G)]
Summary of Changes	Following approval of a corporate separation plan, an electric utility shall provide the director of the utilities department (or their designee) with a summary of any changes in the CAM at least every twelve months. [Source: 4901:1-37-08 (H)]
Company Contact	The compliance officer designated by the electric utility will act as the contact for the staff when staff seeks data regarding affiliate transactions, personnel transfers, and the sharing of employees. [Source: 4901: 1-37-08 (I)]
Commission Inspection	The staff may perform an audit of the CAM in order to ensure compliance with this rule.[Source: 4901:1-37-08(J)]

TRANSFER PRICING

The Commission’s corporate separation rule, as expressed in the CAM requirements themselves (see above), provides that "the method for charging costs and transferring assets shall be based on fully allocated costs." [Note: Also see Am. Sub. S. B. No. 3]

REBUTTABLE PRESUMPTION	Transactions made in accordance with rules, regulations, or service agreements, approved by the Federal Energy Regulatory Commission, and the Securities and Exchange Commission, and the Commission which rules the electric utility shall maintain in its CAM, and file with the Commission shall provide a rebuttable resumption of compliance with the costing principles contained in Ohio's corporate separation rules. [Source: 4901:1-37-04 (A) (6)]
REPORTING REQUIREMENTS	The Commission's corporate separation rule, as expressed in the CAM requirements themselves (see above), provides that "*an electric utility shall provide the director of the utilities department (or their designee) with a summary of any changes in the CAM at least every twelve months.*"
AUDITS	The staff of the PUCO will perform audits to test compliance with the CAM requirements and other provisions of the commission's corporate separation rules.

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OKLAHOMA RULES AND REGULATIONS

SUMMARY

Oklahoma's requirements applicable to affiliate transactions are focused on the Oklahoma Corporation Commission's (the Commission's or the OCC's) ability to access the books and records of Public Service Corporation of Oklahoma (PSO) and its AEP affiliates as stated in the Stipulation approved by the OCC in Cause No. PUD 980000444, dated April 16, 1999. Other requirements are contained in orders issued by the OCC.

ACCESS TO BOOKS AND RECORDS

Section 5 of the Stipulation in Cause No. 980000444 concerning the proposed merger of American Electric Power Company, Inc. and Central and South West Corporation addresses the issue of access to books and records as captured in the following table:

SUBJECT	***REQUIREMENT***
Access to Books and Records of AEP and Its Affiliates	Subject to regulatory authority, the OCC and Attorney General will either have access in Oklahoma to copies of books and records of AEP and its affiliates and subsidiaries (including their participation in joint ventures) with respect to matters and activities that relate to Oklahoma retail rates or AEP will pay reasonable and prudently incurred travel expenses to conduct on-site review of the books and records.
Access to Books and Records of PSO	The OCC and Attorney General will have access to the books and records of PSO to the degree required to fully audit, examine, or otherwise investigate transactions between PSO and AEP affiliates.

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STANDARDS FOR TRANSACTIONS BETWEEN UTILITIES AND AFFILIATE(S)

The Oklahoma's rules and requirements applicable to Affiliate Transactions are contained in the Oklahoma Corporation Commission's (OCC) Electric Utility Rules adopted May 2, 2005, and effective July 1, 2005.

The applicable rules and requirements are captured in the following table:

SUBJECT	REQUIREMENTS
Transactions with Affiliates	(1) Electric utilities must apply any tariff provision in the same manner to the same or similarly situated persons if there is discretion in the application of the provision. (2) Electric utilities must strictly enforce a tariff provision for which there is no discretion in the application of the provision. (3) Except as necessary for physical operational reasons, electric utilities may not, through a tariff provision or otherwise, give their affiliates or knowingly give customers of their affiliates preference over other utility customers in matters relating to any service offered including, but not limited to: generation, transmission, distribution and ancillary services, scheduling, balancing, or curtailment policy. (4) Unless such disclosure is made public simultaneously or as near to the event as possible, electric utilities shall not disclose to their

SUBJECT	REQUIREMENTS
Transactions with Affiliates (Cont'd)	affiliates any information which they receive from, a non-affiliated customer, a potential customer, any agent of such customer, or potential customer, or other entity seeking to supply electricity to a customer or potential customer. (5) An electric utility's operating employees and the operating employees of its affiliate must function independently of each other and shall be employed by separate corporate entities. (6) Electric utilities and their affiliates shall keep separate books and records. (7) Electric utilities shall establish a complaint procedure. In the event of the electric utility and the complainant are unable to resolve a complaint, the complainant may address the complaint to the Commission. (8) With respect to any transaction or agreement relating in any way to electric generation, transmission, distribution and ancillary services, an electric utility shall conduct all such transactions with any of its affiliates on an arm's length basis. (9) The Commission shall resolve affiliate transactions disputes or abuses on a case-by-case basis. Any aggrieved party may file a complaint with

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SUBJECT	REQUIREMENTS
Transactions with Affiliates (Cont'd)	the Commission alleging the particulars giving rise to the alleged dispute or abuse. (10) Electric utilities must process all similar requests for electric services in the same manner and within the same period of time. (11) Electric utilities shall not provide leads to their affiliates and shall refrain from giving any appearance that the electric utility speaks on behalf of its affiliate(s). Nor shall the affiliate trade upon, promote or advertise its affiliation or suggest that it receives preferential treatment as a result of its affiliation. The use of a common corporate or parent holding company name shall not be a violation of this provision so long as the regulated utility and the affiliate entities can be distinguished. (12) Electric utilities, except for billing and collection services and customer service, or by order of the Commission, shall not share their customer list or related customer information with affiliates unless the information is simultaneously shared with non-affiliate entities. (13) The electric utility shall not communicate with any third party that any advantage in the provision of electric services may accrue to such third party as a result of that third

SUBJECT	REQUIREMENTS
Transactions with Affiliates (Cont'd)	party's dealings with the electric utility's affiliate. [165:35-31-19]

TRANSFER PRICING AND OTHER TRANSACTION REQUIREMENTS

The OCC's rules contain very specific requirements for transactions between a utility and its affiliates including the pricing of such transactions. The applicable requirements are captured in the following table:

SUBJECT	REQUIREMENTS
Transfer Pricing and Other	• **Transactions between a utility and its affiliates.** A utility shall not subsidize the business activities of any affiliate with revenues from a regulated service. A utility cannot recover more that its reasonable fair share of the fully allocated costs for any transaction or shared services. • **Contemporaneous record requirement.** A utility shall maintain a contemporaneous written record of all individual transactions with a value equal to or over one million dollars with its affiliates, excluding those involving shared services or corporate support services and those transactions governed by tariffs or special contracts. Such records, which shall include at a minimum, the date of the transactions, name of affiliate(s) involved, name

SUBJECT	REQUIREMENTS
Transfer Pricing and Other (Cont'd)	of a utility employee knowledgeable about the transaction, and a detailed description of the transaction with appropriate support documentation for review purposes, shall be maintained by the utility for three years. • **Transfer of assets.** Except as otherwise required by federal statute or regulation or pursuant to Commission authorized competitive bidding, tariffs, special contract, or as otherwise ordered by the Commission; cost recovery for property transferred from a utility to its affiliate shall be priced at the "higher of cost or fair market value." Except as otherwise required by federal statute or regulation, or pursuant to Commission authorized competitive bidding, tariffs, special contract or as otherwise ordered by the Commission; asset valuation and transfers of property transferred from an affiliate to its utility shall be priced at the "lower of cost or fair market value." No matter the origin of the transaction, all transfers between a utility and an affiliate will be individually

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SUBJECT	REQUIREMENTS
Transfer Pricing and Other (Cont'd)	scrutinized by the Commission on a case-by-case basis. • **Sale of products or services.** Except as otherwise required by federal or state statute or regulation, or pursuant to Commission authorized competitive bidding, tariffs, special contract or as otherwise ordered by the Commission; any sale of products and services provided from the affiliate to the utility shall be priced at the "lower of cost or fair market value." Except as otherwise required by federal statute or regulation, or pursuant to Commission authorized competitive bidding, tariffs, special contract or as otherwise ordered by the Commission; any sale of jurisdictional products and services provided from the utility to the affiliate shall be priced at "higher of cost or fair market value." • **Joint purchases.** A utility may make a joint purchase with its affiliates of goods and services involving goods and/or services necessary

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Transfer Pricing and Other (Cont'd)	for utility operations. The utility must ensure that all joint purchases are priced, reported, and conducted in a manner that permits clear identification of the utility's and the affiliate's allocations of such purchases. • **Tying arrangements prohibited.** Unless otherwise allowed by the Commission through a rule, order or tariff, a utility shall not condition the provision of any product, service, pricing benefit, waivers or alternative terms or conditions upon the purchase of any other good or service from the utility's affiliate. [165:35-31-20]
Separate Books and Financial Transactions	A utility shall keep separate books of accounts and records from its affiliates. The Commission may review records relating to any transaction between a utility and an affiliate to ensure compliance with this Subchapter including the records of both the utility and the affiliate relating to any transaction. (1) In accordance with generally accepted accounting principles, a utility shall record all transactions with its

SUBJECT	REQUIREMENTS
Separate Books and Financial Transactions (Cont'd)	affiliates, whether they involve direct or indirect expenses. (2) A utility shall prepare non-GAAP financial statements that are not consolidated with those of its affiliates. (3) A utility shall have a cost allocation manual or upon Commission request, be able to provide its cost allocation methodology in written form with supporting documentation. Such records shall reflect the transaction and the allocated costs, with supporting documentation, to justify the valuation. • **Limited credit, investment or financing support by a utility.** A utility may share credit, investment, or financing arrangements with its affiliates if it complies with paragraphs (1) and (2) of this Subsection. (1) The utility shall implement adequate safeguards precluding employees of an affiliate from gaining access to information in a manner that would allow or provide a means to transfer confidential information from a utility to an affiliate, create an opportunity for

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Separate Books and Financial Transactions (Cont'd)	preferential treatment or unfair competitive advantage, lead to customer confusion, or create an opportunity for preferential treatment or unfair competitive advantage, lead to customer confusion, or create opportunities for subsidization of affiliates. (2) Where an affiliate obtains credit under any arrangement that would include a pledge of any assets in the rate base of the utility or a pledge of cash necessary for utility operations the transactions shall be reviewed by the Commission on a case-by-case basis. • **Cost of financing transactions of any affiliate.** The cost of any financial transactions, in part or in full, or any debt, equity, trading activity, or derivative, of any parent company, holding company or any affiliate, which has a direct or indirect financial or cost impact upon the utility shall be reviewed by the Commission on a case-by-case basis. [165:35-31-21]

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TENNESSEE RULES AND REQUIREMENTS

SUMMARY

Tennessee has no specific rules and requirements applicable to cost allocations and affiliate transactions. In 1999, the Consumer Advocate Division of the Office of the Attorney General made a request for a rulemaking concerning proposed rules for cost allocations and affiliate transactions before the Tennessee Regulatory Authority.

COMMISSION ACTION

The request for rulemaking by the Consumer Advocate Division was placed on the Tennessee Regulatory Authority's docket in 1999 and comments and reply comments were filed by Kingsport Power Company and the Consumer Advocate Division as well as other parties (Docket No. 98-00690).

Any rules or requirements of the Tennessee Regulatory Authority applicable to cost allocations and affiliate transactions will be summarized in this document when and if they are adopted.

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SUMMARY

Texas' rules and requirements applicable to cost allocations and affiliate transactions are contained in the Texas Utilities Code (PURA) Section 36.058 and the substantive rules applicable to electric service providers adopted by the Public Utility Commission of Texas (the PUCT, or the Commission).

DOCUMENTATION REQUIREMENTS

The PUCT's documentation requirements for affiliate transactions are contained in its substantive rules, as captured in the following table:

SUBJECT	REQUIREMENT
Separate Books and Records	• A utility and its affiliates shall keep separate books of accounts and records, and the Commission may review records relating to transactions between a utility and an affiliate. • A utility shall record all transactions with its affiliates, whether they involve direct or indirect expenses, in accordance with generally accepted accounting principles or state and federal guidelines, as appropriate. • A utility shall prepare financial statements that are not consolidated with those of its affiliates. [§25.272(d)(6)(A)-(B)]

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TRANSFER PRICING AND OTHER TRANSACTION REQUIREMENTS

The PUCT's substantive rules contain very specific requirements for transactions between a utility and its affiliates, including the pricing of such transactions. The applicable requirements are captured in the following table:

SUBJECT	REQUIREMENT
Transactions with All Affiliates	• **General.** A utility shall not subsidize the business activities of any affiliate with revenues from a regulated service. In accordance with PURA and the Commission's rules, a utility and its affiliates shall fully allocate costs for any shared services, including corporate support services, offices, employees, property, equipment, computer systems, information systems, and any other shared assets, services, or products. [§25.272(e)(1)] • **Sale of products or services by a utility.** Unless otherwise approved by the Commission and except for corporate support services, any sale of a product or service by a utility shall be governed by a tariff approved by the Commission. Products and services shall be made available to any third

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SUBJECT	REQUIREMENT
Transactions with All Affiliates (Cont'd)	party entity on the same terms and conditions as the utility makes those products and services available to its affiliates. [§25.272(e)(1)(A)] • **Purchase of products, services, or assets by a utility from its affiliate.** Products, services, and assets shall be priced at levels that are fair and reasonable to the customers of the utility and that reflect the market value of the product, service, or asset. [§25.272(e)(1)(B)] • **Transfers of assets.** Except for asset transfers implementing unbundling pursuant to PURA §39.051, asset valuation in accordance with PURA §39.262, and transfers of property pursuant to a financing order issued under PURA, Chapter 39, Subchapter G, assets transferred from a utility to its affiliates shall be priced at levels that are fair and reasonable to the customers of the utility and that reflect the market value of the assets or the utility's fully allocated cost to provide

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SUBJECT	REQUIREMENT
Transactions with All Affiliates (Cont'	those assets. [§25.272(e)(1)(C)] • **Transfer of assets implementing restructuring legislation.** The transfer from a utility to an affiliate of assets implementing unbundling pursuant to PURA §39.051, asset valuation in accordance with PURA §39.262, and transfers of property pursuant to a financing order issued under PURA, Chapter 39, Subchapter G will be reviewed by the Commission pursuant to the applicable provisions of PURA, and any rules implementing those provisions. [§25.272(e)(1)(D)]
Transactions with Competitive Affiliates	• **General.** Unless otherwise allowed in this sub-section on transactions between a utility and its affiliates, transactions between a utility and its competitive affiliates shall be at arm's length. A utility shall maintain a contemporaneous written record of all transactions with its competitive affiliates, except those involving corporate support services and those transactions governed by tariffs. Such records,

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Transactions with Competitive Affiliates (Cont'd)	which shall include the date of the transaction, name of the affiliate involved, name of a utility employee knowledgeable about the transaction, and a description of the transaction, shall be maintained by the utility for three years. In addition to the requirements specified above for transactions with all affiliates, the provisions cited in the following bullets apply to transactions between utilities and their competitive affiliates. [§25.272(e)(2)] • **Provision of corporate support services.** A utility may engage in transactions directly related to the provision of corporate support services with its competitive affiliates. Such provision of corporate support services shall not allow or provide a means for the transfer of confidential information from the utility to the competitive affiliate, create the opportunity for preferential treatment or unfair competitive advantage, lead to

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SUBJECT	REQUIREMENT
Transactions with Competitive Affiliates (Cont'd)	customer confusion, or create significant opportunities for cross-subsidization of the competitive affiliate (emphasis added). [§25.272(e)(2)(A)] • **Purchase of products or services by a utility from its competitive affiliate.** Except for corporate support services, a utility may not enter into a transaction to purchase a product or service from a competitive affiliate that has a per unit value of $75,000 or more, or a total value of $1 million or more, unless the transaction is the result of a fair, competitive bidding process formalized in a contract subject to the provisions of §25.273 of this title (relating to Contracts Between Electric Utilities and Their Competitive Affiliates). [§25.272(e)(2)(B)] • **Transfers of assets.** Except for asset transfers facilitating unbundling pursuant to PURA §39.051, asset valuation in accordance with PURA §39.362, and transfers of property pursuant to a financing order issued under PURA, Chapter 39,

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SUBJECT	REQUIREMENT
Transactions with Competitive Affiliates (Cont'd)	Subchapter G, any transfer from a utility to its competitive affiliates of assets with a per unit value of $75,000 or more, or a total value of $1 million or more, must be the result of a fair, competitive bidding process formalized in a contract subject to the provisions of §25.273 of this title. [§25.272(e)(2)(C)]

REPORTING REQUIREMENTS

The PUCT's requirements applicable to the reporting of affiliate transactions by electric utilities are contained in its substantive rules, as captured in the following table:

SUBJECT	REQUIURREMENT
Annual Report of Affiliate Transactions	A "Report of Affiliate Activities" shall be filed annually with the Commission. Using forms approved by the Commission, a utility shall report activities among itself and its affiliates. The report shall be filed by June 1, and shall encompass the period from January 1 through December 31 of the preceding year. [§25.84 (d)]
Copies of Contracts or Agreements	A utility shall reduce to writing and file with the Commission copies of any contracts or agreements it has with its affiliates. This requirement is not satisfied by the filing of an

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Copies of Contracts or Agreements (Cont'd)	earnings report. All contracts or agreements shall be filed by June 1 of each year as attachments to the annual "Report of Affiliate Activities." In subsequent years, if no significant changes have been made to the contract or agreement, an amendment sheet may be filed in lieu of refiling the entire contract or agreement. [§25.84 (e)]
Tracking Migration of Employees	A utility shall track and document the movement between the utility and its competitive affiliates of all employees engaged in transmission and distribution system operations, including persons employed by a service company affiliated with the utility who are engaged in transmission or distribution system operations on a day-to-day basis or have knowledge of transmission or distribution system operations. Employee migration information shall be included in the utility's annual "Report of Affiliate Activities." The tracking information shall include an identification code for the migrating employee, the respective titles held while employed at each entity, and the effective dates of the migration. [§25.84 (f)]

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REPORTING REQUIREMENTS

Section 25.84 of the Commission's substantive rules requires that informal code of conduct complaints, deviations from the code of conduct to ensure public safety and system reliability, and updates for all approved changes to the utility's code of conduct compliance plan, including those changes that result from the creation of a new affiliate, be included in the utility's annual "Report of Affiliate Activities." In addition §25.272(b)(3) of the Commission's substantive rules requires a utility to file a notice with the Commission of any provision in the Commission's Code of Conduct for Electric Utilities and Their Affiliates (i.e., §25.272) that conflicts with the orders and regulations of the Federal Energy Regulatory Commission or the Securities and Exchange Commission.

AUDIT REQUIREMENTS

The PUCT's audit requirements applicable to affiliate transactions by electric utilities are contained in its substantive rules, as captured in the following table:

SUBJECT	***REQUIREMENT***
General	A utility and its affiliates shall maintain sufficient records to allow for an audit of the transactions between the utility and its affiliates. At any time, the Commission may, at its discretion, require a utility to initiate, at the utility's expense, an audit of transactions between the utility and its affiliates performed by an independent third party. [§25.272 (d)(6)(C)]

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SUBJECT	***REQUIREMENT***
Compliance Audits Compliance Audits (Cont'd)	No later than one year after the utility has unbundled pursuant to PURA §39.051, and, at a minimum, every third year thereafter, the utility shall have an audit prepared by independent auditors that verifies that the utility is in compliance with §25.272 (relating to Code of Conduct for Electric Utilities and Their Affiliates). The utility shall file the results of each audit with the Commission within one month of the audit's completion. The cost of the audits shall not be charged to utility ratepayers. [§25.272 (i)(3)]

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VIRGINIA RULES AND REQUIREMENTS

SUMMARY

The Code of Virginia requires approval of contracts between a public service company and any affiliated interests. Virginia's rules and requirements applicable to cost allocations and affiliate transactions can be found in the Code and in the regulations and orders of the Virginia State Corporation Commission (the SCC, or the Commission), particularly the Final Orders in Case Nos. PUA000029 and PUE010013.

SCC APPROVAL

No contract or arrangement providing for the furnishing of management, supervisory, construction, engineering, accounting, legal, financial or similar services, and no contract or arrangement for the purchase, sale, lease or exchange of any property, right or thing, other than those above enumerated, or for the purchase or sale of treasury bonds or treasury capital stock made or entered into between a public service company and any affiliated interest shall be valid or effective unless and until it shall have been filed with and approved by the Commission [Code of VA §56-77].

DOCUMENTATION

The Commission's documentation requirements related to affiliate transactions are captured in the following table:

SUBJECT	***REQUIREMENT***
Separate Books and Records	Each affiliated competitive service provider shall maintain separate books of accounts and records. [20 VAC 5-312-30 C]
Access to Books and Records	The Commission may inspect the books, papers, records and documents of, and require special reports and statements from, every generation company affiliated

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SUBJECT	***REQUIREMENT***
Access to Books and Records (Cont'd)	with a local distribution company regarding transactions with its local distribution company affiliate. Upon complaint or on its own initiative, the Commission may also (I) investigate alleged violations of this charter, and (ii) seek to resolve any complaints filed with the Commission against any such affiliated generation company. [20 VAC 5-202-30 B 7]
Employee Transfers	An affiliated competitive service provider shall document each occasion that an employee of its affiliated local distribution company, or of the transmission provider that serves its affiliated local distribution company, becomes one of its employees and each occasion that one of its employees becomes an employee of its affiliated local distribution company or the transmission provider that serves its affiliated local distribution company. Upon staff's request, such information shall be filed with the SCC that identifies each such occasion. Such information shall include a listing of each employee transferred and a brief description of each associated position and responsibility. [20 VAC 5-

SUBJECT	REQUIREMENT
Employee Transfers (Cont'd)	312-30 B 3]

TRANSFER PRICING

The SCC's transfer pricing rules applicable to affiliate transactions between the local distribution company (LDC) and certain affiliate are contained in various orders of the Commission.

Rules Applicable to Functional Separation of Incumbent Electric Utilities under the Virginia Restructuring Act(Case No. PUA000029)

The SCC's rules applicable to the functional separation of incumbent electric utilities under the Virginia Electric Utility Restructuring Act contain specific transfer pricing requirements for transactions between the LDC and an affiliated generation company as captured in the following table:

SUBJECT	REQUIREMENT
Sale of Non-Tariffed Services, Facilities and Products	LDCs shall be compensated at the greater of fully distributed cost or market price for all non-tariffed services, facilities, and products provided to an affiliated generation company.
Purchase of Non-Tariffed Services, Facilities and Products	An affiliated generation company shall be compensated at the lower of fully distributed cost or market price for all non-tariffed services, facilities, and products provided to the LDC.
Unavailable Market Prices	If market price data are unavailable for purposes of such calculations, non-tariffed services, facilities and products shall be compensated at fully distributed costs. In such event, the LDC shall document its

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SUBJECT	REQUIREMENT
Unavailable Market Prices (Cont'd)	efforts to determine market price data and its basis for concluding that such price data are unavailable.

[Source: 20 VAC 5-202-30 B 5 a]

Rules Applicable to Retail Access (Case No. PUE010013)

The SCC's rules for retail access contain specific transfer pricing requirements concerning transactions between the local distribution company and its affiliated competitive service providers as captured in the following table:

SUBJECT	REQUIREMENT
Sale of Non-Tariffed Services, Facilities and Products	The local distribution company shall be compensated at the greater of fully distributed cost or market price for all non-tariffed services, facilities, and products provided to an affiliated competitive service provider.
Purchase of Non-Tariffed Services, Facilities and Products	An affiliated competitive service provider shall be compensated at the lower of fully distributed cost pr market price for all non-tariffed services, facilities, and products provided to the local distribution company.
Unavailable Market Prices	If market price data are unavailable, non-tariffed services, facilities and products shall be compensated at fully distributed cost and the local distribution company shall document its efforts to determine market price data and its basis for

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SUBJECT	***REQUIREMENT***
Unavailable Market Prices (Cont'd)	concluding that such price data are unavailable. Notification of a determination of the unavailability of market price data shall be included with the annual report of affiliate transactions that is required to be filed by the local distribution company with the SCC.

[Source: 20 VAC 5-312-30 I. 1.]

AFFILIATE TRANSACTION REPORTING REQUIREMENTS

Virginia's general reporting requirements for affiliate transactions have evolved through several recent affiliate agreement approval orders and are summarized in the following table:

SUBJECT	***REQUIREMENT***
Annual Report of Affiliate Transactions	An annual report of affiliate transactions shall be filed by May 1 of each year with the SCC's Director of Public Utility Accounting for transactions for the prior calendar year. The annual report shall include all affiliate agreements/ arrangements regardless of amount involved and shall supersede all previous reporting requirements for affiliate transactions (except, see Statement of Utility Assets Sold, Purchased or Acquired below). The report shall contain the

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SUBJECT	REQUIREMENT
Annual Report of Affiliate Transactions (Cont'd)	following information: 1. Affiliate's name 2. Description of each affiliate arrangement/agreement 3. Dates of each affiliate arrangement/agreement 4. Total dollar amount of each affiliate arrangement/agreement 5. Component costs of each arrangement/agreement where services are provided to an affiliate (i.e., direct/indirect labor, fringe benefits, travel/housing, materials, supplies, indirect miscellaneous expenses, equipment/facilities charges, and overhead) 6. Profit component of each arrangement/agreement where services are provided to an affiliate and how such component is determined 7. Comparable market values and documentation related to each arrangement/ agreement 8. Percent/dollar amount of each affiliate arrangement/agreement charged to expense and/or capital accounts, and 9. Allocation bases/factors for allocated costs. Transfers of assets between APCO and AEPC with values of $100,000 or less must be reported in the annual report of affiliated transactions.

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SUBJECT	***REQUIREMENT***
	All transfers of assets between APCO and AEPC with a value exceeding $100,000 require prior Commission approval. *[Source: SCC Order, dated March 4, 1998, in Case No. PUA970035]* The Annual Report of Affiliate Transactions shall also include copies of all executed Greenfield Site Agreements between APCO and AEPC along with a description of the particulars of each site as well as the book value of the underlying land relative to the proposed per site license fee of $10,200/year (less any volume discount for multiple sites). *[Source: SCC Order, dated December 6, 199, in Case No. PU990053]*
Annual Report Under the Virginia Electric Utility Restructur-ing Act	Local distribution companies (LDCs) shall file annually, with the Commission, a report that shall, at a minimum, include: (i) the amount and description of each type of non-tariffed service provided to or by an affiliated generation company; (ii) accounts debited or credited; and (iii) the compensation basis used (i.e., market price or fully distributed cost). The LDC shall make available to the Commission’s staff, upon request, the following documentation for each agreement and arrangement

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SUBJECT	***REQUIREMENT***
	where services are provided to or by an affiliated generation company: (i) component costs (i.e., direct or indirect labor, fringe benefits, travel or housing, materials, supplies, indirect miscellaneous expenses, equipment or facilities charges, and overhead); (ii) profit component; and (iii) comparable market values and documentation. *[Source: 20 VAC 5=202-30 B 6]*
Annual Report Required by the Rules Governing Retail Access to Competitive Energy Services	The local distribution company (LDC) shall file annually, with the SCC, a report that shall, at a minimum, include: the amount and description of each type of non-tariffed service provided to or by an affiliated competitive service provider; accounts debited or credited; and the compensation basis used, i.e., market price or fully distributed cost. The LDC shall maintain the following documentation for each agreement and arrangement where such services are provided to or by an affiliated competitive service provider and make such documentation available to staff upon request: (i) component costs (i.e., direct or indirect labor, fringe benefits, travel or housing, materials, supplies, indirect miscellaneous expenses, equipment or facilities

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VIRGINIA RULES AND REQUIREMENTS

SUBJECT	***REQUIREMENT***
	charges, and overhead; (ii) profit component; and (iii) comparable market values, with supporting documentation. *[20 VAC 5-312-30 I 2]*
Schedule of Utility Assets Purchased or Sold	APCO must file annually a schedule of purchases from affiliates and sales to affiliates, if any, of utility assets, amounting to less than $25,000 for each such transaction, made during the preceding calendar year. *[Source: SCC Order, dated August 29, 1956, in Case No. 13162, and SCC order, dated February 20, 1981, in Case PUA810009]*

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WEST VIRGINIA RULES AND REQUIREMENTS

SUMMARY

The West Virginia Code requires approval of contracts between a public utility and its affiliates. The orders issued by the Public Service Commission of West Virginia (PSC, or Commission) concerning such matters contain requirements related to affiliate transactions.

PSC APPROVAL

Unless the consent and approval of the PSC is obtained, no public utility in West Virginia may, by any means, direct or indirect, enter into any contract or arrangement for management, construction, engineering, supply or financial services or for the furnishing of any other service, property or thing with any affiliated corporation, person or interest *[West Virginia Code § 24-2-12]*. The individual orders issued by the Commission approving such contracts establish requirements applicable to specific transactions with affiliates.

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Section

Introduction

Subject

OVERVIEW (PROCEDURES)

SUMMARY	At AEP, cost allocations between regulated and non-regulated operations take place through intercompany billings and affiliate transactions. The intercompany billing process and related procedures move costs between AEP System's regulated electric utilities and their non-regulated affiliates. The cost allocation process recognizes the nature of the work performed for the respective parties and their use of services and facilities.
TRANSACTIONS	The financial transaction coding process used by AEP is the first step in separating costs between regulated and non-regulated operations.
TIME REPORTING	Labor cost is a large component of the total cost allocated between regulated and non-regulated operations. Time reporting and labor costing procedures are in place to ensure that labor costs are properly allocated and billed to the companies that benefit from the services which are performed.
AEPSC BILLING SYSTEM	AEPSC performs services for American Electric Power Company, Inc., the parent holding company, and most subsidiaries in the AEP System. AEPSC uses a work order system to collect and bill costs to its Afflilate companies for the services that it performs.
INTERCOMPANY BILLING	Other AEP System companies share costs with their affiliates through an intercompany billing process. This process transfers the cost of performing services and conducting projects for affiliates in the AEP System.

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Section

Introduction

Subject

OVERVIEW (PROCEDURES)

INTERUNIT ACCOUNTING	Certain transactions are allocated between companies through inter-unit accounting whereby transactions are recorded in the first instance by the companies for which the transactions have been incurred.
ASSET TRANSFERS	Plant and equipment as well as materials and supplies are transferred among the AEP System companies based on who uses the items. Procedures are in place to properly account for the transfer and sale of those items.

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Section

Transactions

Subject

OVERVIEW

SUMMARY

The process of cost allocation between regulated and non-regulated operations begins with the coding of expenses and other transactions.

RESPONSIBILITY

Transaction coding is the responsibility of the business units that budget for and initiate the transactions.

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CODING BLOCKS

Various coding blocks, also known as chartfields, are used to code financial transactions for accounting and cost allocation purposes.

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Transactions

Subject

CODING

SUMMARY	Proper chartfield coding is mandatory to ensure accurate financial reports and inter-company billings.
CODING RESPONSIBILITY	Chartfield coding is the responsibility of the business units who incur various expenditures, and who report their labor hours. These expenses are initiated and approved by the business units in accordance with their operating plans and financial budgets.
MAINTENANCE OF CHARTFIELD VALUES	The Service Corporation Accounting group is primarily responsible for maintaining chartfield values. The business units request changes to the chartfield values based on their need to track and manage costs, bill affiliated companies and comply with external reporting requirements. This group evaluates all requests in connection with its oversight responsibilities related to internal budgeting, cost allocations, and external reporting. Approved changes are implemented on a timely basis.

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Transactions

Subject

CHARTFIELDS

SUMMARY

AEP's accounting systems use chartfields or coding blocks to classify and accumulate transactions for financial and managerial accounting and reporting. Each chartfield/coding block is used for a specific purpose.

CODING BLOCKS

GENERAL LEDGER CHARTFIELDS:

General Ledger Business Unit	Account Number	Department ID	Product Code	Affiliate Code	Operating Unit Code

PROJECTS CHARTFIELDS:

Project Costing Business Unit	Project ID	Work Order *(Project Activity)*	Cost Component *(Resource Type)*	Activity Code *(Resource Category)*	Tracking Code *(Resource Subcategory)*

General Ledger Business Unit

The **General Ledger Business Unit** identifies the AEP System company or company segment for which the transaction is recorded. Each AEP System Company is assigned a unique code. For example, American Electric Power Company, Inc. is Business Unit 100 and AEP Texas Central-Distribution is Business Unit 211.

Account Number

The **Account Number** records the transaction in the appropriate balance sheet or income statement account using the FERC System of Accounts.

Department ID

The **Department ID** connects the transaction to the responsible organization for reporting and budgeting purposes.

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Transactions

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CHARTFIELDS

Product Code	The **Product Code** identifies transactions with the services and products provided by the Shared Services groups, including Business Logistics, Human Resources and Information Technology.
Affiliate Code	The **Affiliate Code** identifies transactions conducted with an affiliate. The **General Ledger Business Unit** code of the affiliate is entered in this coding block, if applicable. The codes in this chartfield are used in preparing consolidated financial statements.
Operating Unit Code	The **Operating Unit** code sub-divides transactions for special reporting purposes largely related to tax reporting, rate case, and other matters. Valid values include, among others, state abbreviations.
Project Costing Business Unit	The **Project Costing Business Unit** connects the transaction with the responsible budgeting group or area for project reporting purposes.
Project ID	The **Project ID** connects the transaction with a budget project. A budget project allows budgeted and actual costs to be captured for managerial reporting purposes.
Work Order	The **Work Order** is the billing mechanism used to capture and bill like costs, and connects the transaction with a planned project that generally has a set beginning date, a projected end date and an estimated cost to complete. Work Orders include construction and retirement work, R&D work, IT projects, non-regulated activities, and other special projects and transactions.

Attached to each **Work Order,** as an attribute, is a Benefiting Location Code that identifies the location or area that benefits from the work (i.e., the activity or project that is being performed). A benefiting location can define, among other things, a power plant, a generating unit at a power plant, or a region. Each benefiting location further defines the company or group of companies that operate in the particular location or area. For example, benefiting location code 1160 is only applicable to Kammer Plant Unit 3 and pertains to the Generation ledger for Ohio Power Company; and, benefiting location code 1178 pertains to the Transmission ledgers of Appalachian Power Company, Kentucky Power Company and Kingsport Power Company.

Cost Component

The **Cost Component** relates the transaction to a specific type of cost such as labor, travel, materials, or outside services.

Activity Code

The **Activity Code** identifies the activity being performed. Examples of defined work activities are: “Respond to Customer Inquiries,” “Process Payroll” and “Coordinate Federal Income Tax Returns & Reports.” The Activity code directs the billing allocation formula for some work orders.

Tracking Code

The **Tracking Code** sub-divides accounting transactions for cost tracking purposes. Among other things, the tracking code is used to track vehicle and building expenditures by vehicle number or building number. Certain equipment maintenance costs are also tracked.

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Section

Time Reporting

Subject

OVERVIEW

SUMMARY

AEP’s time reporting systems are designed to collect the chartfield information needed to apportion costs between regulated and non-regulated activities.

TIME RECORDS

Each AEP employee, or a responsible timekeeper, must complete a time record for each pay period.

03-03-02

LABOR COSTING

The cost of labor makes up a high percentage of the service cost which is apportioned between regulated and non-regulated activities.

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Section

Time Reporting

Subject

TIME RECORDS

SUMMARY

AEP follows a system of positive time reporting whereby all employees, are required, either personally or through an appointed timekeeper, to provide Payroll with a full accounting of their productive and non-productive time classifications. Time records are prepared for each pay period. Examples of non-productive time include vacation time, holidays, jury duty and other paid absences.

FEATURES

Positive time reporting is the process by which each employee accounts for the total number of hours in each pay period, including overtime and paid absences. The positive time reporting process used by AEP encompasses the following features:

- Forms the basis for assigning labor costs by accounting for all activities and time spent by activity on a pay period basis
- Accounts for time in hourly increments as small as a one-tenth of an hour
- Accumulates and summarizes time spent on a reported line-item basis
- Requires all chartfield values needed to account for the time spent and to report labor costs
- Requires the amount of time reported for a given pay period to at least equal the total hours in the pay period
- Does not assume employees are working only on regulated activities or only on non-regulated activities. The

FEATURES (Cont'd)

actual time spent must be reported and classified to the applicable activities and/or projects based on the work performed.

- As employees spend and report time, the cost of the time is directly attributable to regulated and non-regulated operations based on benefiting location or it could apply to an indirect cost pool.

APPROVALS

All time records must be approved by the employee's immediate supervisor or the supervisor's designee. Audit Services performs periodic studies to determine that the time reported by group supervisors has a reasonable relationship to the time reported by their direct reports.

ELECTRONIC PROCESSING

In most cases, time is reported and approved electronically. The reported time is available to be viewed on-line for a period of time before it is archived.

Employees can view their accrued and used vacation hours on-line using AEP's intranet.

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Section

Time Reporting

Subject

LABOR COSTING

SUMMARY

Labor costing is the process of pricing the time reported by employees for the purpose of apportioning their labor cost to the activities that they perform. The cost of labor is a high percentage of the total service cost apportioned among AEP's regulated and non-regulated affiliates.

FEATURES

AEP's labor costing process, in conjunction with time reporting, has been designed to meet the following four criteria:

- it must be practical and cost effective to apply
- it must contain safeguards against material misclassifications between regulated and non-regulated operations and between regulated and non-regulated products and services
- it must be adequately documented
- it must provide an audit trail that can be used for procedural testing and for determining the accuracy of results.

The labor costing process used by AEP employs the following features:

- productive time is priced using the employee's hourly rate of pay which, for salaried employees, is derived by using one of two methods: *(i)* by dividing the employee's annual salary by 2,080 hours, or *(ii)* by dividing the employee's current pay period salary by the total number of hours worked during the pay period (including non-compensated overtime hours worked by exempt employees)

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Time Reporting

Subject

LABOR COSTING

FEATURES (Cont'd)

- non-productive pay is accrued, expensed and distributed as a percentage of labor dollars
- where applicable, the cost of incentive pay and severance pay is also accrued and expensed; and it too follows the distribution of labor dollars.

CONTROLS

Where applicable, appropriate controls are maintained for balancing the total amount of labor cost distributed to the total cost incurred or paid.

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Section

AEPSC Billing System

Subject

OVERVIEW

SUMMARY	AEPSC is a wholly-owned subsidiary of AEP, a registered public utility holding company. AEPSC provides certain managerial and professional services including administrative and engineering services to affiliated companies in the AEP holding company system and periodically to unaffiliated companies. As a subsidiary service company, AEPSC and its billings are subject to the regulation of the Federal Energy Regulatory Commission (FERC) under the Public Utility Holding Company Act of 2005.
SYSTEM OF INTERNAL CONTROLS	Effective operation of the AEPSC work order billing system is tied to AEP's overall system of internal controls. **03-04-02**
WORK ORDER ACCOUNTING	AEPSC maintains a work order system for allocating and billing costs in accordance with the applicable Uniform System of Accounts for centralized service companies. **03-04-03**
BILLING ALLOCATIONS	Billing allocations are performed using Allocation Factors (i.e., allocation factors) approved by the SEC under PUHCA 1935 and continued after it's repeal. **03-04-04**
REPORTS	AEPSC prepares a monthly billing report for all billed costs. **03-04-05**

SUMMARY

Effective operation of AEPSC’s work order and billing system is tied to AEP’s overall system of internal controls. The more relevant controls and administrative procedures include accountability, allocability, budgeting, time-reporting review and approval, billing review, dispute resolution, periodic service evaluations, and internal auditing.

RESPONSIBILITIES

The business units and process owners who code and approve transactions for processing through the AEPSC billing system are responsible for final results. Employees can access electronic databases that contain titles and descriptions of all applicable codes.

Changes in facts and circumstances that affect the billing process must be addressed in a rapid and responsible manner.

The Corporate Planning and Budgeting group along with Corporate Accounting are responsible for assisting the business units and AEPSC’s client companies in evaluating the monthly billing results on a company by company basis. Also see “Billing Review” below.

ALLOCABILITY

Through the transaction coding process, clients are billed only for the services and costs that pertain to them. Shareable costs are billed using allocation factors. The approved billing system is designed to result in a fair and equitable allocation of cost among all client companies, regulated and non-regulated. AEPSC employees are provided information and trained to achieve these results relative to their areas of responsibility.

BUDGETING	Each year AEPSC prepares an annual budget for the services it will provide during the next calendar year. The budgets are prepared by each AEPSC department. Corporate Planning & Budgeting and Business Unit Budget Coordinators generate monthly performance reports that compare actual cost against the budget. Performance results can be viewed by Department, by Account, or by Activity, and also by Affiliate company. AEPSC's managers are primarily responsible for analyzing and explaining cost variances incurred while performing their work. Additionally, AEPSC and its affiliates are jointly responsible for analyzing and explaining the cost variances incurred through the AEPSC billings. AEPSC's annual budgets are consistent with and support AEP's corporate-wide strategic performance objectives. AEP's Board of Directors, with the assistance of executive management, approves the annual budgets for AEPSC, the utility companies and other AEP affiliates.
WORK ORDER PROCESSING REVIEW	The Accounting department reviews requests for new AEPSC Work Orders. The review includes (1) Appropriate descriptions – to ensure that the users will understand the type of costs to be accumulated in each work order. (2) Appropriate benefiting location – to ensure that the proper affiliated company or group of companies will be billed (3) Appropriate billing allocation factor – to verify (based on the work being performed) that the appropriate cost drivers are being used for the type of service being performed such as Number of Employees, Transmission Pole Miles, Number of Retail Electric

	Customers, or Total Assets.
BILLING SYSTEM CONTROLS	Specific controls related to the billing system include (1) The Accounting department reviews the reasonableness of the statistics, by affiliate company, that are used to allocate costs by comparing them to other statistics, amounts used in prior periods, etc. (2) Reports are generated by the billings system to reconcile/confirm that all amounts were allocated and the total dollars received for processing were billed out. (3) An automatic e-mail is sent to the Accounting department which identifies any errors created during Journal Generation of the AEPSC Bill. (4) The Accounting department confirms the AEPSC net income is zero each month-end to ensure that all expenses incurred were billed. (5) The Accounting department reviews the list of AEP affiliate companies every month to assure billing statistics are accumulated and posted properly for a newly created affiliate companies, or removed for inactivated affiliate companies. Please see Appendix 99-00-04 for information regarding the billing allocation factors that are used by AEPSC and their update frequency.
PRE-BILLING TRANS-ACTIONS REVIEW	Various controls exist surrounding the detailed accounting transactions that are processed by the AEPSC billing system, including: (1) Numerous edits/validations are performed mechanically at the time transactions are entered into the accounting system. For example, the validation routines will not permit a labor expense Account to be used in conjunction with non-labor costs. (2) Prior to running the monthly AEPSC billing process, Accounting reviews certain

	accounting transactions to ascertain if any items are misclassified based on certain criteria. Correction entries are prepared, if necessary, prior to the bill processing, For example, transactions charges to income tax FERC expense account should be charged to the income tax work order. (3) An “unbillable” report is run numerous times prior to processing of the bill. This report identifies transactions that will not bill due to recently inactivated Work Orders, invalid combinations of statistics, etc. Correction entries are made as necessary prior to running the bill.
ALLOCATION	Shared costs are billed using approved allocation factors. The billing systems is designed to result in a fair and equitable allocation of cost amount all affiliate companies. As mentioned above under “Responsibilities”, information is readily available to employees to assist with the proper coding of transactions in order to achieve these results relative to their areas of responsibility.
TIME REPORTING REVIEW AND APPROVAL	AEPSC uses positive time reporting whereby time records are submitted by each AEPSC employee, on a bi-weekly basis. Supervisors, or their designated delegates, review and approve the time records for the employees in their respective groups. In addition to the normal approval process, periodically the Accounting department provides reports to each AEPSC manager for review and validation of their employees; labor charges. The report indicates the companies that each employee billed, the work performed for the company, the labor hours charged, and the work orders(s) used to bill the hours. This report provides an

additional control to ensure employees were billing correctly and that their managers concurred with the billing. Managers were required to sign the report indicating their review and approval, and return the signed copy to Accounting. If a manager has questions about an employee's time charges, or believes a correction is required, the manager communicates those concerns to Accounting.

AFFILIATED BILLING REVIEW

Monthly, Utility General & Regulated Accounting sends reports to the State Operating Companies Regional Presidents (and/or their staff), and other members of management, for their review and approval of the AEPSC Work Order billing by affiliate company.

The services performed and the amounts billed are reviewed for accuracy on behalf of the regulated utilities and AEPSC's other affiliated clients. The performing organizations initiate all needed corrections and Corporate Accounting processes the corrections.

DISPUTE RESOLUTION

The monthly AEPSC billings to the affiliate Operating companies are submitted to the AEP state Business Operations Support groups for their review and approval. The AEPSC bill approval process for the Business Operations Support groups includes various steps. Monthly, Directors review the AEPSC departments allocating costs to their companies to determine whether it appears reasonable for each department to be allocating to that operating company. Also monthly, Directors notify AEPSC of their approval of the monthly AEPSC billing, noting any issues needing resolved as a result of their monthly review. Any issues arising from the above reviews are coordinated through the affected AEPSC department and the AEPSC Controllers department, which will be responsible for resolving issues raised by the operating companies and making appropriate adjustments. Each of the above steps is documented, including approvals, explanations of variances, and any adjustments resulting from this review and approval process. Directors are responsible for retaining documentation for a minimum of two years.

If a resolution cannot be reached among the parties, the dispute is referred to the Chief Financial Officer or another appropriate member of executive management.

SERVICE EVALUATIONS

Internal customer input and an internal customer-oriented philosophy are necessary in order to keep AEPSC operating efficiently and at cost-competitive levels.

Internal customer surveys are used to measure performance and internal customer satisfaction. The internal customer surveys, along with the budgeting process and service level agreements, are used to seek customer input relative to the quantity, quality and value of the various services being provided by AEPSC to other groups within the AEP holding company system.

Whenever feasible, and to the extent necessary, cost levels and business practices are benchmarked against other companies both within and outside the electric utility industry.

INTERNAL AUDITING

The AEPSC Audit Services department performs periodic audits of the AEPSC billing system. The purpose of the audits is to examine the internal controls over the billing process and to ascertain that billing allocations are being performed in accordance with the approved Allocation Factors and in accordance with the Service Agreements AEPSC has with its affiliated clients.

EXTERNAL AUDITING

Annually, AEPSC is required to provide audited financial statements to various banks and leasing companies, and therefore is subject to an audit by an outside auditing firm, currently Deloitte & Touche. This audit includes an audit of various transactions through the billing system to verify accuracy of the procedures and amounts billed to affiliates.

STATE AND FEDERAL AUDITS AND REPORTING

STATE AUDITS:

AEPSC is subject to periodic state affiliate and code of conduct audits, in order to comply with certain state regulatory requirements. For example, Texas requires an affiliated code of conduct audit every three years.

FERC AUDITS:

Effective with the passage of the Public Utility Holding Company Act of 2005 (which became effective February 6, 2006) AEPSC is now regulated by the Federal Energy Regulatory Commission, and as such is subject to FERC oversight and audit.

FERC REPORTING:

The FERC requires a detailed annual financial report for services companies, the FERC Form 60. This report contains detailed AEPSC information, including amounts billed to each affiliate company.

These periodic audits and annual reporting requirements provide additional controls governing AEPSC’s accounting routines, financial transactions, and billing to affiliates.

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Section

AEPSC Billing System

Subject

Work Order Accounting

SUMMARY

AEPSC uses a work order system for the accumulation of cost on a job, project or functional basis. It includes schedules and worksheets used to account for charges billed to single and groups of associate and nonassociate companies.

COST IDENTIFICATION

As a subsidiary service company, AEPSC identifies billable costs using two separate chartfields (i.e., transaction coding blocks); namely,

- Activity (through General “G” Work Orders) and
- Work Order.

Each of these chartfields is defined elsewhere in this manual (look up “Chartfields” in the Table of Contents or the Alphabetic Subject Index to determine the applicable Document Number).

General (i.e., “G”) work orders have been established to assign the benefiting location to general services that are billed by “Activity”.

FUNCTION AND TYPES OF WORK ORDERS

A billable cost is derived by using a Work Order or Activity with a Benefiting Location (including “G” Work Orders). While Work Order and Activity define the nature of the service performed, the Benefiting Location identifies the company or group of companies for which the service is performed. Benefiting Location is not a chartfield, but it is an attribute of each billable Work Order. AEPSC uses the following types of Work Orders (billable and non-billable):

Direct – A Direct Work Order is used when the service being provided benefits a single company or company segment. The monthly cost accumulated for a Direct Work Order is billed 100% to the company for which the service was

FUNCTION AND TYPES OF WORK ORDER (Cont'd)

performed as designated by the Benefiting Location code associated with the service.

Allocated – An Allocated Work Order is used when the service being performed benefits two or more companies or company segments. The monthly cost accumulated for an Allocated Work Order is allocated and billed to the companies for which the service is performed as designated by the Benefiting Location code associated with the service.

The AEPSC billing system uses specific company cost-causative Allocation Factors to allocate costs that are accumulated under Allocated Work Orders.

SCFringe – The SCFringe Work Order is used to accumulate the cost of labor-related overhead. Labor-related overhead includes, among other things, payroll taxes and employee benefits such as pension and medical expense.

SCFringe is charged to client companies in proportion to the distribution of AEPSC's labor dollars.

While not part of SCFringe, it should be noted that the cost of compensated absences such as vacation and holiday pay is also charged to client companies based on the distribution of AEPSC's labor dollars.

Departmental Overhead – The SDOH9999 Departmental Overhead Work Order is used to accumulate certain overhead costs applicable to each department. This Work Order may be direct charged by each respective department for general departmental expenses.

In addition, each department receives its fair share of costs incurred by AEPSC's Shared Services groups (namely, Business Logistics, Human Resources and Information Technology).

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Many of the Shared Services groups' expenses are initially deferred on the Balance Sheet and subsequently billed to the departments that benefit from the costs based on various statistics contained in the Shared Services Repository. For example, occupancy expenses (depreciation, rent, utilities, property taxes, etc.) are allocated to departments based on Square Footage; desktop computing expenses are allocated to departments based on the Number of Personal Computers; etc.

Departmental Overhead expenses are allocated to client companies in proportion to the labor charged by each department to the client companies.

Internal Support Costs Overhead – The Internal Support Costs (ISC) Overhead Work Order is used to identify the expenses incurred in support of AEPSC's overall operations. ISC includes all expenses identified with work order G0000103, which has an attribute of Benefiting Location 103 (the code for AEPSC). For example, the expenses incurred in processing the payroll for AEPSC's employees and in paying AEPSC's vendors are included in ISC overhead is allocated to client companies in proportion to the total cost charged to each company.

ACTIVITY AND WORK ORDER REQUESTS

Service requests fall into two major categories:

- Activity, and
- Work Order.

As the overseer of the budgeting process, AEPSC's Corporate Planning and Budgeting group is responsible for approving all requests for adding or deleting Activities. The Corporate Planning and Budgeting group processes all requests for opening or closing new Activities while the Corporate Accounting group processes all requests for new AEPSC Work Orders.

The ABM Activity Request Form – This form requires the following information:

Line Item	Information
Requested By	Name of requestor. Electronic requests are automatically populated with requestor's required information, date and time.
Effective Date	The requesting business unit recommends an effective date for use of the new activity.
Activity Number	The requesting business unit provides the Activity Number only when an existing activity is being changed.
Activity Description	The requesting business unit provides the proposed title of the new activity (e.g., "Develop Coal Delivery Forecast").
Process Group	The requesting business unit provides the name of the high-level process group to which the new activity is related (e.g., "Generate Energy").
Major Process	The requesting business unit provides the name of the high-level major process to which the new activity is related (e.g., "Procure, Produce & Deliver Fuel").
Business Process	The requesting business unit provides the name of the high-level business process to which the

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AEPSC Billing System

Subject
Work Order Accounting

Line Item	Information
	activity is related (e.g., “Procure Coal”).
Purpose and Use	The requesting business unit provides a description of the new activity, its purpose and use.
Task List	Provide a list of all the steps and preparation undertaken to arrive at the request.
Suggested FERC Accounts	The requesting business unit provides the suggested FERC account.
Service Corp Attrribution Basis	The requesting business unit recommends an Allocation Factor for use.
Cost Drivers	The requesting business unit provides the reasons for the request.

See the ILLUSTRATIONS at the end of this document for a copy of the Activity Request Change Form.

Work Order Request Form – This form requires the following information:

Line Item	Information
Recommended Title	The requesting business unit provides the recom-mended work order title.
Project Costing Business Unit	The requesting business unit provides the Project Costing Business Unit identification.
Budget Project	The requesting business unit provides the applicable Budget Project code.
Work Order Type	The requesting business unit provides the Work

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Section

AEPSC Billing System

Subject

Work Order Accounting

Line Item	Information
	Order type.
Estimated Total Costs to be incurred by AEPSC	The requesting business unit supplies the estimated cost of the work performed.
Estimated Duration	The requesting business unit provides the start the estimated completion date.
Description of Service(s) To Be Rendered	The requesting business unit supplies a description of the work order based on the nature and scope of the project to be performed.
Benefiting Location	The requesting business unit supplies the applicable benefiting location code based on the company or class of companies that will benefit from the work order. The requester can select the benefiting location code either by Name or by Number. The benefiting location will become an attribute of the work order.

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Section

AEPSC Billing System

Subject

Work Order Accounting

Line Item	Information
Recommended Allocation Factor	The requesting business unit supplies the recommended Allocation Factor code for the work order. The Allocation Factor code identifies the proposed method of allocation for Allocated work orders. The Allocation Factor becomes an attribute of the work order. Work orders that pertain to a single company should be assigned an Allocation Factor code of “39, Direct”.
Shared Services Deferrals	Shared Services Departments, including Human Resources, Information Technology and Business Logistics, have the opportunity to defer actual amounts and bill their costs via subsequent Service Level Agreements (SLA) Processing. These departments are first identified and then indicate (Yes/No) if the amounts are to be deferred on a work order by work order basis.
Additional Remarks	The requesting business unit provides any special project or accounting instructions related to the work order or makes reference to any attachments.
Others To Be Notified When Request Is Approved	The requesting business unit provides a list of employees to be notified when the work order is

Line Item	Information
	opened for charges.
Are you the Sponsoring Supervisor for This Request?	The requester must indicate if he or she is the sponsoring supervisor for this work order request.
Other Reviewers	The sponsoring supervisor must approve the request. In addition, the Corporate Accounting group must accept or decline each request.

See the ILLUSTRATIONS at the end of this document for a copy of the Work Order Request Form.

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ABM Activity

Request ID New

Request Title:

Note:
The first approver is always the Business Unit Budget Coordinator. Requestor must select coordinator's name using 'Edit Approver List' button above.

Click here to view list of Budget Coordinators .

Requestor Information :

Requested By :	Donald W Roberts/AEPIN
Requestor ID :	S191469
Employe Type :	AEP Emp
Phone Number :	8-200-2996
Floor/Location :	26
Business Unit :	103
Department ID :	10284
Request Date :	04/20/2009 11:20:41 AM
Approval Status :	**New**
Request Status :	**Waiting Action Group Processing**

Requestor	Previous Approvers	Current Approver	Future Approvers
Donald W Roberts	None		Entered when submitted Chtfld Regulated Accounting Chtfld Commercial Accounting Chtfld Service Corp Accounting Chtfld Business Integration & Strategy

Requester	Approvers
Donald W Roberts	Entered when submitted Chtfld Regulated Accounting Chtfld Commercial Accounting Chtfld Service Corp Accounting Chtfld Business Integration & Strategy

Approval Information
Request Information

Request Type : New

Request Title :

Reason for Request :

Detailed Description of New Chartfield Request :

Action Group

Notify on Status Change

Chartfield Maintenance	Chtlfd Generation Dept

Effective Date :

05/20/2009

Activity Detail :

Activity Number :

Activity Description :

Process Group :

Major Process :

Business Process :

Purpose and Use :

Task List :

Suggested Ferc Accts :

Sv Corp Attr Basis :

Output Measure :

Cost Drivers :

You're ready to Submit ! Please click the "Submit" button at the top of the form.

Communication & History

Automatically notified on Status change : Donald W Roberts, Entered when submitted, Chtfld Regulated Accounting, Chtfld Commercial Accounting, Chtfld Service Corp Accounting, Chtfld Business Integration & Strategy, Chtlfd Generation Dept, ,

Additional people to notify on Status change :

To:
cc:
bcc:
Subject: Regarding Chartfield Request #New...

MEMO

Send Memo as Email **<-- OR -->** Record Memo in History Only

History

AEPSC WORK ORDER REQUEST

Requested by Donald W Roberts 20-Apr-09 at 10:39 AM

REQUEST HEADER

Recommended Work Order Title:

Project Costing Business Unit (PCBU):

Budget Project:

Work Order Type:

Estimated Total Cost to be incurred by AEPSC: ☐ On-Going

Estimated Duration Start:

End:

Full Description of the work to be performed:

Enter Effective Date for Work Order [z Proj Act Addl]:

Work Order Number:

Enter the GL Account:

BENEFITING LOCATION

Benefiting Location: -

03-04-03

Reason/Support for billing these Companies:

Billed Company:

ALLOCATION/ATTRIBUTION BASIS

Recommended Allocation/Attribution Basis: -

Reason/Support for using this Allocation/Attribution to bill:

SHARED SERVICES

Is this Work Order for Business Logistics, Information Technology, or Human Resources?
○ Yes
● No

WORK ORDER STATUS

Effective Date:

Work Order Status:

SCNA WORK ORDER INFORMATION

Effective Date of Billing Method
GL Unit
Company (Resource Sub Category)
Amount

ADDITIONAL INFORMATION

Additional Remarks and File Attachments:

Others To Be Notified When Request Is Approved:

Are you the Roll Group Supervisor for this request? ○ Yes ○ No

APPROVAL/ROUTING

Sponsoring Roll Group Supervisor
Approver 2 Status List:
Approver 3 Status List:

Show Edit History ...

AUDIT

Date Entered 04/20/2009 10:39:21 AM By Donald W Roberts/AEPIN
Modification History:

Cost Allocation Manual

Section

AEPSC Billing System

Subject

BILLING ALLOCATIONS

SUMMARY

Each Allocated Service ID, whether related to an Activity or a Work Order, is assigned an appropriate Allocation Factor code that, along with the Benefiting Location code, ultimately determines the dollars of cost that will be charged to each client company. Allocation Factor codes are assigned according to the nature of the services performed.

Each Direct Service ID is assigned an Allocation Factor code of "39" which is fixed at 100%.

FUNCTION OF THE ALLOCATION FACTOR CODE

The Allocation Factor code identifies the statistical factor that will be used to calculate the percentage of cost applicable to each client company. The assigned code points to a table that includes the company-specific values needed to calculate the allocation percentages.

ROLE OF CORPORATE ACCOUNTING

An accounting administrator in the Corporate Accounting group has primary responsibility for ensuring that the Allocation Factor code assigned to each Allocated Service ID is relevant to the service being performed. Corporate Accounting is also responsible for ensuring that the company-specific statistical values needed for each Allocation Factor are accurate and kept up to date. The values are refreshed according to the intervals determined for each Allocation Factor (e.g., monthly, quarterly, semi-annually and annually).

The Allocation Factor assigned to each Allocated Service ID should be the most relevant cost-causative cost driver.

PROCESS

The requestor of a new Activity or Work Order is required to recommend an appropriate Allocation Factor code. Requestors are in the best position to recommend an appropriate Allocation Factor code since they are intimately familiar with the work to be performed and with the inherent cost drivers. Corporate Accounting reviews all Allocation Factor code selections for reasonableness.

EXAMPLES

Examples of the appropriate use of Allocation Factors are captured in the following table:

Activity/Shared Service	Allocation Factor
191. Maintain Transmission Right-of-Way	28. Number of Transmission Pole Miles
340. Process payroll	09. Number of employees
663. Perform Stores Accounting	26. Number of Stores Transactions

LIST OF APPROVED ALLOCATION FACTORS

The APPENDIX to this manual contains a list of all the approved Allocation Factors.

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Document Number **03-04-05**

Cost Allocation Manual

Section

AEPSC Billing System

Subject

REPORTS

SUMMARY

An electronic journal entry is created by the AEPSC billing system as part of the billing process to record the accounts receivable and revenue on AEPSC's books, and to record the corresponding distribution and accounts payable on the associate companies' books (billing interface).

BILL FORMAT

The following represents a view of the monthly bill for services rendered by AEPSC to an associate company:

AUDIT TRAIL

An audit trail is maintained for all AEPSC billing system transactions starting with the source documents all the way through general ledger posting.

The AEPSC billing system produces a journal entry that is posted to each respective company's general ledger on a monthly basis. The mask for this journal entry is "SCBBILxxxx". The alpha section of the mask is constant. The numeric section of the mask is assigned the next available journal entry number each month for each company.

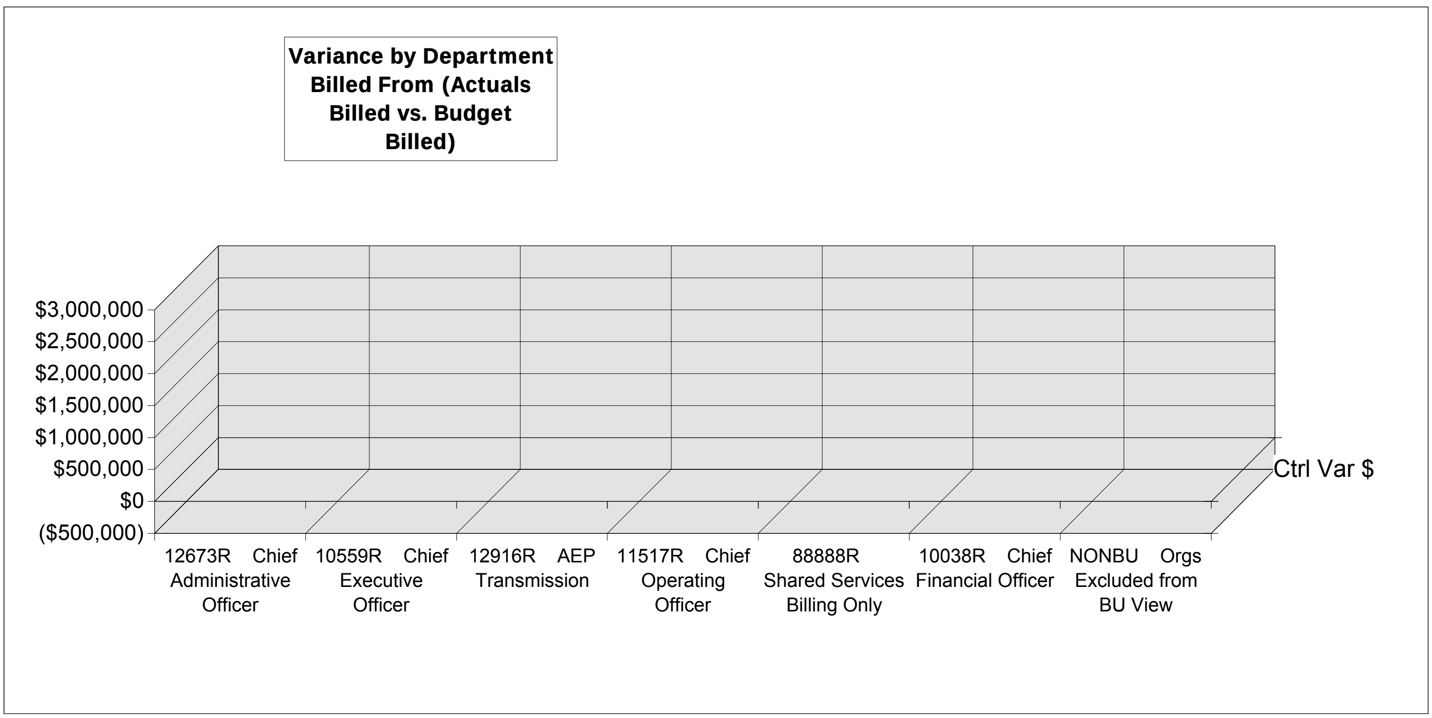
AEP Service Corporation Billing Summary

ASSOCIATE COMPANY

December 2011

Total AEPSC Bill

Billed From Department...	Actuals Billed	Budget Billed	Variance
12673R Chief Administrative Officer			
10559R Chief Executive Officer			
12916R AEP Transmission			
11517R Chief Operating Officer			
88888R Shared Services Billing Only			
10038R Chief Financial Officer			
NONBU Orgs Excluded from BU View			
TOTAL			



AEP Service Corporation Billing Summary - by Cost Type

ASSOCIATE COMPANY

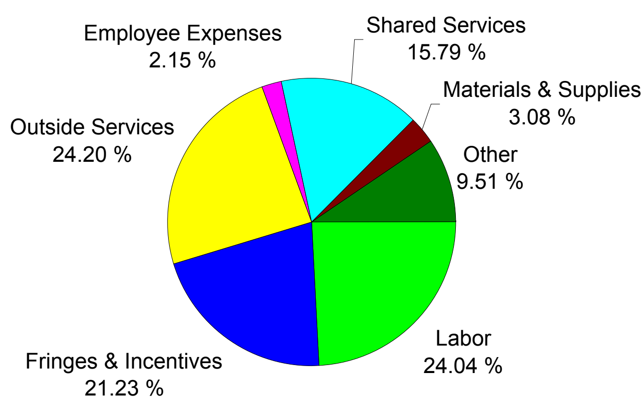
December 2011

Total AEPSC Bill

AEP Service Corporation Actuals Billed by Department and Cost Type

Department	Actuals Billed	Labor	Fringes & Incentives	Outside Services	Employee Expenses	Shared Services	Materials & Supplies	Other
11517R Chief Operating Officer								
12673R Chief Administrative Officer								
10559R Chief Executive Officer								
12916R AEP Transmission								
10038R Chief Financial Officer								
88888R Shared Services Billing Only								
NONBU Orgs Excluded from BU View								
TOTAL	Sum:							

Percentage of Cost Type - Actuals Billed From AEP Service Corporation



AEP Service Corporation Billing Summary - by Function

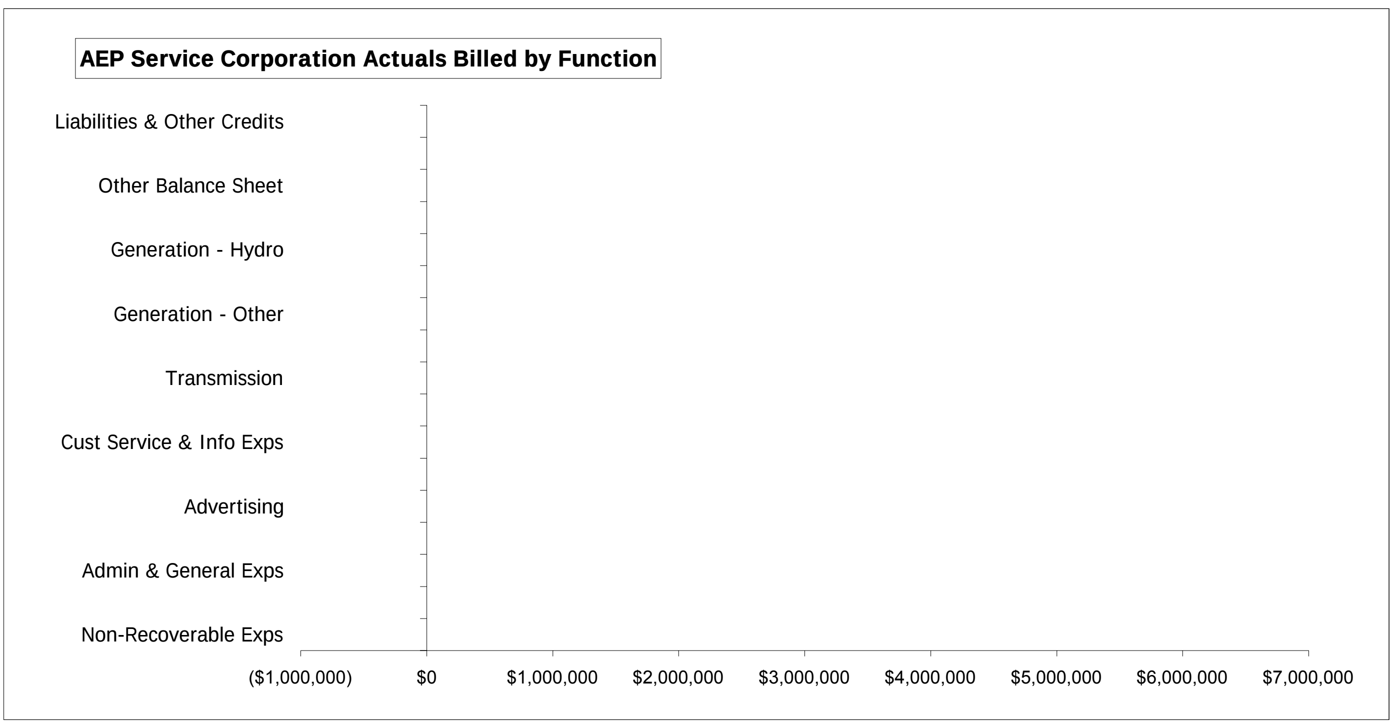
ASSOCIATE COMPANY

December 2011

Total AEPSC Bill

AEP Service Corporation Actuals Billed by Function and Cost Type

Function	Actuals Billed	Labor	Fringes & Incentives	Outside Services	Employee Expenses	Shared Services	Materials & Supplies	Other
Liabilities & Other Credits								
Capital								
Other Balance Sheet								
Generation - Steam								
Generation - Hydro								
Generation - Nuclear								
Generation - Other								
Misc Power Supply Exps								
Transmission								
Distribution								
Cust Service & Info Exps								
Customer Accounts								
Advertising								
Regulatory Commission Exp								
Admin & General Exps								
Assoc Business Dev								
Non-Recoverable Exps								
TOTAL								



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Document Number **03-05-01**

Cost Allocation Manual

Section

Intercompany Billing

Subject

OVERVIEW

SUMMARY	The PeopleSoft general ledger system used by AEP allows transactions to be coded for intercompany billing.
BILLING SYSTEM	AEP's intercompany billing process automates the accounting for costs incurred by one AEP System company for the exclusive or mutual benefit of one or more affiliates.

03-05-02

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Document Number 03-05-02

Cost Allocation Manual

Section

Intercompany Billing

Subject

BILLING SYSTEM

SUMMARY

Intercompany billing of O&M and capital costs automates the accounting for work performed by one company for the exclusive or mutual benefit of one or more affiliates. This process allows the performing company to incur the cost and bill it to the appropriate benefiting company or companies. All intercompany billing transactions between companies are summarized on a monthly basis, resulting in one net billing between companies.

USES

Intercompany billing is used most often to share operating expenses or when one company performs services for another company. The Affiliate Transaction Agreement, dated December 31, 1996, and the Mutual Assistance Agreement, dated July 30, 1987 provide the basis of the intercompany billing.

Costs incurred which are subject to intercompany billing can include, among other costs, O&M or capital company labor including appropriate transportation and labor fringes, purchased materials or services, materials issued from company storerooms, and rental charges for use of another company’s facilities.

CODING REQUIREMENTS

The initiation of the intercompany billing process requires the proper use of chartfield values. An intercompany billing transaction is initiated whenever a benefiting location number is different than the performing company’s business unit code. Benefiting location numbers can be either 100% billed or shared among multiple companies. A 100% billed and a multiple company benefiting location example follow:

CODING REQUIREMENTS (Cont’d)

Example: 100% billed Benefiting Location
The duties performed by the West Virginia

Rates Department benefit the AEP customers within the state of West Virginia. Both Appalachian Power Company and Wheeling Power Company - Distribution serve customers in West Virginia. All Rates Department employees serving West Virginia are on the payroll of Appalachian Power Company.

Whenever the Rates Department performs work exclusively on a Wheeling Power Company - Distribution rate case, their labor and expenses are classified to benefiting location 210. The use of 210 benefiting location results in a 100% billing to Wheeling Power Company - Distribution. This intercompany billing establishes an accounts receivable entry for Appalachian Power Company, the performing company, and a corresponding accounts payable entry for Wheeling Power Company - Distribution, the company benefiting from the work.

Example: Shared Benefiting Location
An invoice is received for aerial patrol services performed for the Central Transmission Region. Since this work has been performed for the benefit of all five companies served by the Central Transmission Region, the processing company charges a multiple company benefiting location. This multi-company benefiting location shares the cost among the five companies served by the Central Transmission Region.

Since the invoice pertains to transmission services, the cost incurred will be allocated among the five companies using an Allocation Factor of transmission pole miles. This intercompany billing establishes an accounts receivable entry for the performing company and a corresponding accounts payable entry for the four remaining benefiting companies.

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Cost Allocation Manual

Section

Intercompany Billing

Subject

BILLING SYSTEM

INTERCOMPANY BILLING COST ALLOCATIONS

All intercompany billing allocations are either direct (i.e., 100%) or are allocated among the appropriate companies based on the applicable multi-company benefiting location code. Every multi-company transaction is allocated using one of the approved Allocation Factors for service company billings. The Allocation Factor must be appropriate for the function for which the cost is incurred. For example, cost incurred for the performance of transmission services would be allocated using an Allocation Factor of number of transmission pole miles.

AUDIT TRAIL

An audit trail is maintained for all intercompany billing transactions starting with the source documents all the way through general ledger posting.

The intercompany billing procedure produces journal entries that are posted to each respective company's general ledger on a monthly basis. The journal entry mask for the intercompany billing process is "INTCOMxxxx". The alpha section in each mask is constant. The numeric section of the masks is assigned the next available journal entry number each month for each company.

Any given intercompany journal entry can contain several thousand lines of data each month.

The accounts receivable and accounts payable transactions created by the intercompany billing process are assigned account numbers 1460006 and 2340027, respectively.

CASH SETTLEMENT

Intercompany billing transactions are settled through the AEP money pool among money pool participants. Non-money pool participants settle-up through cash disbursements.

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Document Number **03-06-01**

Cost Allocation Manual

Section

InterUnit Accounting

Subject

OVERVIEW

SUMMARY	The PeopleSoft general ledger and accounts payable systems used by AEP allow transactions to be recorded that pertain to two or more companies.
JOINT PAYMENTS AND JOURNAL TRANSACTIONS	InterUnit accounting can be applied to accounts payable processing or general ledger journal entry processing.

03-06-02

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Document Number **03-06-02**

Cost Allocation Manual

Section

InterUnit Accounting

Subject

JOINT PAYMENTS AND JOURNAL TRANSACTIONS

SUMMARY

InterUnit accounting automates the process of accounting for transactions that affect two or more affiliated companies. The process automatically generates the general ledger transactions applicable to each company. All InterUnit accounting transactions are summarized on a daily basis, resulting in a net amount due to and from each company, by affiliated company.

USES

InterUnit accounting can be applied to accounts payable processing, accounts receivable processing, or to general ledger journal entry processing.

InterUnit accounting is used whenever one company (i.e., business unit) processes a vendor invoice, deposits funds, or classifies journal entry transactions that pertain to one or more other affiliated companies.

The InterUnit accounting feature within the PeopleSoft software saves time, reduces processing costs, accurately creates reciprocal transactions, and provides for an efficient settlement routine. It simplifies the intercompany billing process by eliminating the need to prepare and handle paper billings. A complimentary process also summarizes and nets the daily InterUnit activity that occurs between companies.

CODING REQUIREMENTS

InterUnit accounting requires the proper use of business unit codes. An InterUnit transaction is initiated by entering a business unit code on a transaction classification line that is different from the processing company’s business unit code.

The uses of InterUnit accounting and the related coding requirements are illustrated by the following three examples:

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Cost Allocation Manual

Section

InterUnit Accounting

Subject

JOINT PAYMENTS AND JOURNAL TRANSACTIONS

CODING REQUIREMENTS (Cont'd)

Example of invoice processing through accounts payable:

An invoice is received for legal services performed for six of AEP's generating companies. Since the invoice pertains to more than one company, the invoice can be processed by one of the companies using at least six lines of accounting classification; that is, one line for each company. InterUnit accounting will be triggered for all the lines of classification that have a business unit code that is different from the processing company's business unit code.

For each line of classification with a different business unit code, the InterUnit accounting process will establish a receivable from associated companies on the processing company's books and a payable to associated companies on the applicable affiliate companies' books. In addition, the balance sheet and expense transactions actually coded on the original accounts payable voucher will automatically be posted to the books of the applicable companies based on the business unit codes that are used.

Example of receipt processed through accounts receivable:

A single wire transfer is received for materials sold by three of AEP's distribution companies. The customer received three separate invoices, one from each distribution company, but chose to wire funds to only one of AEP's distribution companies for full payments to eliminate incurring multiple wire fees.

Cost Allocation Manual

CODING REQUIREMENTS (Cont'd)

The Billing and Accounts Receivable section will apply payment to each distribution company invoice by reflecting the deposit company (i.e.: business unit), which receipted for the wire transfer. Two of the company invoices will have an invoicing business unit different than the deposit business unit. For these two invoices, the InterUnit accounting process will establish a receivable from associated companies on the company rendering the invoice, and a payable to associated companies on the company that deposited the funds. In addition, the bill classification will be relieved on the company that issued the bill to the customer.

Example of general ledger journal entry processing:

A single company (i.e., business unit) operates a messenger delivery service for itself and several affiliates. Corporate Services provides Accounting Services with the amounts to be billed each month to the other companies based on their actual use of the services.

Since this is a recurring transaction, an InterUnit journal entry can be pre-coded with the appropriate chartfield codes, including the applicable business unit codes. The dollar amounts to be billed to the business units and the date of the transaction are the only variables required for journal entry preparation.

When processed, the InterUnit journal entry will record the charges on the benefiting affiliated companies' books and establish an associated company accounts payable. The

CODING REQUIREMENTS (Cont'd)

journal entry will also record the appropriate associated company accounts receivable entries and offset the original charges on the performing company's books. The debits to accounts receivable from associated companies and the credits to accounts payable to associated companies are automatically generated for each journal entry line item that has a business unit code that is different from the performing company's business unit code.

INTERUNIT ACCOUNTING

For InterUnit accounting purposes, the amount applicable to each company must be coded using separate detail lines. The amount for any transaction that pertains to two or more companies should be allocated using one of the approved Allocation Factors for service company billings. The Allocation Factor selected must be appropriate for the type of cost being allocated based on the nature of the activity or project for which the cost is incurred.

AUDIT TRAIL FEATURES

An audit trail is maintained for all InterUnit transactions starting with the source documents all the way through to the general ledger postings.

The InterUnit transactions processed through Accounts Payable and Billing and Accounts Receivable are posted to the general ledger through the daily distribution interfaces. InterUnit journal entries are posted directly to the general ledger.

InterUnit transactions can be viewed on-line through simple queries where the "Business Unit does not equal Business Unit_GL" for accounts payable transactions, where the "Business Unit does not equal Deposit_BU" for accounts receivable, or where the "Business

AUDIT TRAIL FEATURES (Cont'd)

Unit does not equal Business Unit_IU" for general ledger journal entries.

InterUnit accounting creates the affiliated accounts receivable and accounts payable transactions. Account numbers are assigned as follows:

1) if the accounting is generated by either journal entries or Billing and Accounts Receivable, accounts 1460001 and 2340001 reflect the reciprocal receivable and payable, or
2) if InterUnit accounting is generated by Accounts Payable, accounts 1460009 and 2340030 reflect the reciprocal receivable and payable.

AFFILIATED SETTLEMENTS

A settlement process is initiated daily for all InterUnit transactions. Corporate and General Accounting supplies a file to Treasury summarizing each company's net affiliated position for InterUnit transactions. A net payable position results in either increased short-term borrowings or decreased short-term investments in the AEP money pool among money pool participants. A net receivable position results in either increased short-term investments or decreased short-term borrowings in the AEP money pool among money pool participants. Non-money pool participants settle through cash disbursements.

AMERICAN ELECTRIC POWER

Document Number **03-07-01**

Cost Allocation Manual

Section

Asset Transfers

Subject

OVERVIEW

SUMMARY	AEP companies, especially AEP's electric utilities, sell plant and equipment among themselves. AEP companies also sell materials and supplies to each other.
PLANT AND EQUIPMENT	Plant and equipment generally is sold "at cost" (i.e., net book value) to associate companies in the AEP holding company system.
	03-07-02
MATERIALS AND SUPPLIES	Materials and supplies are generally sold to associate companies "at cost" using the selling company's average unit inventory cost.
	03-07-03

SUMMARY

The physical integration of AEP’s power plants and its many circuit miles of transmission and distribution lines and the use of common parts and equipment allow the AEP companies to achieve cost savings by combining their purchasing needs and improving their ability to respond rapidly to emergency situations throughout the entire network.

Such benefits are achieved in part through exchanges of plant and equipment among affiliated utility companies as conditions warrant. The exchanges take place either through short-term rental arrangements (i.e., loans) or through direct sales.

GUIDELINES

Sales

Sales between affiliated regulated utility companies will be transacted at original cost less depreciation, except as permitted by any other applicable order filed with FERC or required by state rule. Sales from regulated affiliates to non-regulated affiliates are priced at higher of cost or market. Sales from non-regulated affiliates to regulated affiliates are prices at lower of cost or market. As allowed by FERC waiver, capitalized spare parts will continue to be transferred between regulated affiliates and AGR at net book value.

AEP Legal-Regulatory is to be informed for the purpose of determining whether any regulatory approvals must be sought, if any proposed sale exceeds the following amounts:

- All utility companies, other than Appalachian Power Company and Wheeling Power Company - $10,000,000

	• Appalachian Power Company - $50,000 for real estate sales, $1,000,000 for all other sales • Wheeling Power Company – any sale of property
Loans	Generally, loans of equipment and other property should be limited to one year or less. Items to be used for a period greater than one year should be sold to the user. Rental fees for loaned property shall cover all applicable costs. Such costs include cost of capital, depreciation, and taxes.

SUMMARY	AEP’s material management groups along with procurement personnel can initiate requests to transfer materials and supplies (M&S) from one AEP storeroom to another. M&S sent from one company’s storeroom to an associate company’s storeroom results in a sale between companies. Sales between affiliated regulated utility companies will be transacted at cost using the selling company’s average unit inventory cost. Sales from regulated affiliates are priced at lower of cost or market.
MONTHLY BILLS TO ASSOCIATE COMPANIES	The company owning the part generates a Monthly bill for M&S shipped during the month to an associate company. This method is used very rarely since most transfers occur through the inter-company journal entries. Each item sold is priced “at cost” using the seller’s average unit inventory cost. Stores expense is added as appropriate. All sales are recorded through associated company accounts receivable and accounts payable (i.e., Accounts 146 and 234, respectively).

AMERICAN ELECTRIC POWER

Document Number **04-01-01**

Cost Allocation Manual

Section

Introduction

Subject

OVERVIEW (DOCUMENTS)

SUMMARY	AEP's state regulatory commissions require certain documents to be maintained in connection with the transactions AEP's regulated utilities have with their affiliates. In some cases, the documents need to be maintained as part of the utility company's Cost Allocation Manual (CAM).
AFFILIATE CONTRACTS	This manual provides a brief description of all contracts and agreements AEP's regulated utilities have with their affiliates. **04-02-01**
DATABASES	Certain databases have been established for reference purposes. The databases described in this manual provide additional information concerning certain subjects in the manual. **04-03-01**
JOB DESCRIPTIONS	The Public Utilities Commission of Ohio requires the job descriptions of certain shared and transferred employees to be maintained as part of the electric utility's CAM. **04-04-01**
COMPLAINT LOG	The Public Utilities Commission of Ohio requires each electric utility to maintain a log of the complaints the utility receives in connection with the Commission's corporate separation rules. The Commission requires the electric utility to include the complaint log in its CAM. **04-05-01**

AMERICAN ELECTRIC POWER

Document Number **04-01-01**

Cost Allocation Manual

Section

Introduction

Subject

OVERVIEW (DOCUMENTS)

BOARD OF DIRECTORS

The Public Utilities Commission of Ohio requires each electric utility in Ohio to keep a copy of the minutes from its board of directors meetings in its CAM.

04-06-01

AMERICAN ELECTRIC POWER

Document Number **04-02-01**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
OVERVIEW

SUMMARY	The AEP System's regulated utilities provide products and services to affiliates and receive products and services from affiliates under various contracts and agreements. Copies of the contracts and agreements are maintained in an electronic database that is incorporated in this manual by reference.
SERVICE AGREEMENTS	AEP's electric utilities receive services from AEPSC. The electric utilities provide incidental services to each other as well as to AEPSC. **04-02-02**
MINING AND TRANSPORTATION	AEP System affiliates provide coal mining, coal preparation and coal handling services as well as transportation services to AEP's regulated utilities. **04-02-03**
CONSULTING SERVICES	Engineering and consulting services are provided by AEP's regulated utilities to certain non-regulated affiliates and vice versa. **04-02-04**
JOINT OPERATING AGREEMENTS	Certain AEP facilities are jointly owned and operated. **04-02-05**
TAX AGREEMENT	American Electric Power Company, Inc. and its AEP System affiliates file a consolidated Federal income tax return and share the consolidated tax liability. **04-02-06**

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Document Number **04-02-01**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
OVERVIEW

MONEY POOL AGREEMENT

AEP and certain of its regulated subsidiaries participate in the AEP System Money Pool. The Money Pool is designed to efficiently match the available cash and short-term borrowing requirements of their participants, minimizing the need for them to borrow from external sources.

04-02-07

NONUTILITY MONEY POOL AGREEMENT

AEP, and certain of its unregulated subsidiaries participate in the AEP System Nonutility Money Pool. The Nonutility Money Pool is designed to efficiently match the available cash and short-term borrowing requirements of their participants, minimizing the need for them to borrow from external sources.

04-02-08

SUMMARY	AEPSC provides various services to the AEP System's regulated utilities and non-regulated affiliates under a standard service agreement with each of the companies served. The regulated utilities also provide services to each other and to AEPSC under other agreements.
AEPSC SERVICE AGREEMENT	AEPSC has a service agreement, in a standard format, with each of the AEP System companies it serves. All agreements are dated June 15, 2000, unless the client company was formed after that date. In addition APCO and Wheeling have updated service agreements dated May 15, 2008. The types of services provided by AEPSC are listed in Document Number **01-03-02** by category and description.
AEPSC SERVICE AGREEMENT WITH TRANSMISSION COMPANIES	AEPSC has a service agreement, in a standard format, with each of the AEP Transmission companies it serves. The agreements have various effective dates depending on when the client company was formed. The types of services provided by AEPSC are included in the list in Document Number **01-03-02** by category and description.
AFFILIATED TRANSACTIONS AGREEMENT	The Affiliated Transactions Agreement, dated December 31, 1996, is among Appalachian Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, Wheeling Power Company and AEPSC. This agreement covers the provision of incidental services, the sale of goods, and use of facilities and vehicles among the participating companies.

OPERATING COMPANY SERVICE AGREEMENT WITH TRANSMISSION COMPANIES	Each Transmission company has a standard affiliate service agreement with the operating company in its jurisdiction. The agreements have various effective dates depending on when the Transmission Company was formed. This agreement covers services in connection with the operation of each Transmission Company's transmission assets. The agreements also contain a provision appointing the operating company as agent for licensing space on the transmission company's facilities.
CSW SYSTEM GENERAL AGREEMENT	The CSW System General Agreement, effective June 1, 1999, is among AEPSC, Central Power and Light, now AEP Texas Central, Public Service Company of Oklahoma, Southwestern Electric Power Company, West Texas Utilities Company, now AEP Texas North and other CSW subsidiaries including CSW Energy, Inc., CSW International, Inc., CSW Credit, Inc., CSW Leasing, Inc., C3 Communications, Inc., CSW Energy Services, Inc., and EnerShop Inc. AEPSC is the successor of Central and South West Services, Inc.
CSW SYSTEM GENERAL AGREEMENT (Cont'd)	This agreement is intended to provide written documentation governing certain transactions between the CSW electric operating companies and by and between the CSW electric operating companies and other CSW subsidiaries to the extent such matters are not addressed in other written agreements.
MUTUAL ASSISTANCE AGREEMENT	The Mutual Assistance Agreement, dated July 30, 1987, is among Appalachian Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power

	Company, Kentucky Power Company, Kingsport Power Company, Ohio Power Company, and Wheeling Power Company. This agreement allows any participating company to request emergency aid from any one or more of the other participating companies for the purpose of restoring electric service caused by natural disasters and other emergencies.
CENTRAL MACHINE SHOP AGREEMENT	The Central Machine Shop Agreement, dated January 1, 1979, is among Appalachian Power Company and the Companies affiliated with American Electric Power, Inc. This agreement covers machine shop services provided by Appalachian Power Company to affiliates within the AEP System.
SYSTEM INTEGRATION AGREEMENT	The System Integration Agreement, as amended, is among Appalachian Power Company, Kentucky Power Company, Ohio Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, and their agent AEPSC; Public Service Company of Oklahoma, Southwestern Electric Power Company, and AEPSC. This agreement provides the contractual basis for coordinated planning, operation, maintenance of the power supply resources of the AEP East Zone and the AEP West Zone to achieve economies consistent with the provision of reliable electric service and an equitable sharing of the benefits and costs of such coordinated arrangements. This agreement is intended to apply in addition to and not in lieu of the AEP Interconnection Agreement and [CSW] Operating Agreement.

AEP INTERCONNECTION AGREEMENT	The AEP Interconnection Agreement, originally dated July 6, 1951 and modified and supplemented, is among Appalachian Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company (Members) and AEPSC (Agent). This agreement provides for the sharing of power and off-system sales.
AEP SYSTEM INTERIM ALLOWANCE AGREEMENT (MODIFICATION No. 1)	This agreement dated July 28, 1994, is among Appalachian Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, Kentucky Power Company, Ohio Power Company (Members) and AEPSC (as Agent). This agreement establishes, among other things an equitable methodology for allocating emission allowances and associated costs and benefits between and among the Members.
OPERATING AGREEMENT	The [CSW] Operating Agreement (CSW no longer exists), dated January 1, 1997, is among CSWS, Central Power and Light Company, Public Service Company of Oklahoma, Southwestern Electric Power Company and West Texas Utilities Company. A restated and amended operating agreement for Public Service Company of Oklahoma and Southwestern Electric Power Company was signed December 21, 2001. This agreement provides the contractual basis for a single interconnected electric system through the coordinated planning, construc-

tion, operation, and maintenance of the above mentioned companies' electric supplies. CSWS has been designated to act as Agent for this agreement.

SYSTEM TRANSMISSION INTEGRATION AGREEMENT

The System Transmission Integration Agreement, dated June 15, 2000, is among Appalachian Power Company, Kentucky Power Company, Ohio Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, and their agent AEPSC; and Public Service Company of Oklahoma, Southwestern Electric Power Company, Central Power and Light, now AEP Texas Central, West Texas Utilities, now AEP Texas North, and their agent CSWS (succeeded by AEPSC).

This agreement provides the contractual basis for coordinated planning, operation and maintenance of the AEP East Zone and the AEP West Zone System Transmission Facilities to achieve economies consistent with the provision of reliable electric service and an equitable sharing of the benefits and costs of such coordinated arrangements.

TRANSMISSION AGREEMENT

The Transmission Agreement, dated April 1, 1984, is among Appalachian Power Company, Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), Indiana Michigan Power Company, Kentucky Power Company, and Ohio Power Company (Members) and AEPSC (Agent).

This agreement provides for the equitable sharing of costs incurred among the Members for their respective high-voltage and extra high-voltage transmission facilities. This agreement is administered by AEPSC.

AEP SYSTEM TRANSMISSION CENTER AGREEMENT	AEP SYSTEM TRANSMISSION AGREEMENT, dated December 1, 2009 between Ohio Power Company and the AEP West operating companies (AEP Texas Central Company, AEP Texas North Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company). This agreement provides for the West Operating Companies to make use of the AEP Transmission Training Center facilities located in Pataskala, OH and owned by AEP Power for the training of transmission line personnel employed by the West Operating Companies.
TRANSMISSION COORDINATION AGREEMENT	This agreement, dated January 1, 1997 and revised October 29, 1999, is among Central Power and Light Company, West Texas Utilities Company, Public Service Company of Oklahoma, and Southwestern Electric Power Company. This agreement provides for the equitable sharing of costs incurred and revenues earned among the members for their respective transmission systems.
THIRD AMENDED AND RESTATED AGENCY AGREEMENT (ACCOUNTS RECEIVABLE)	This agreement, dated August 25, 2004 as amended March 22, 2006 and January 30, 2008, is among AEP Credit, Inc. and certain AEP electric companies. This agreement provides for the sale by the operating companies to AEP Credit, Inc. of accounts receivables arising from the sale and delivery of electricity, gas and other related services in the normal course of business.
THIRD AMENDED AND RESTATED PURCHASE AGREEMENT (ACCOUNTS	This agreement, dated August 25, 2004 as amended March 22, 2006 and January 30, 2008 is among AEP Credit, Inc. and certain AEP

RECEIVABLE)	electric companies. This agreement provides for the agent (Operating Companies) to take any and all steps on behalf of AEP Credit to collect all amounts due under any or all of the receivables arising from the sale and delivery of electricity, gas and other related services in the normal course of business.
ENERGY CONSERVATION MEASURE UTILITY/ENERGY SERVICE COMPANY AGENCY AGREEMENT	This agreement, dated December 22, 1997, is between West Texas Utilities, Inc. and EnerShop, Inc (EnerShop not longer exists). West Texas Utilities, Inc. (WTU) has signed an Energy Conservation Measures Agreement with the United States Government relating to the refurbishing and upgrading of US Government facilities located within the service territory of WTU. EnerShop is authorized as the agent for WTU in completing any Delivery/Task Orders agreed to by WTU and the US Government. These Orders are for energy conservation projects.
FRANKLIN AND INDIANA FRANKLIN PURCHASE CONTRACTS	Franklin Real Estate Company (Franklin) and Indiana Franklin Realty, Inc. (Indiana Franklin) have purchase contracts with AEP's electric utilities (various dates). The contracts provide that Franklin and Indiana Franklin (Sellers) may buy,sell,hold title to, or lease real estate as agents for the benefit of the respective electric utilities (i.e., each Purchaser).
INDIAN MESA INTERCONNECTION AGREEMENT	The Interconnection Agreements dated March 19, 2001, are between West Texas Utilities, now AEP Texas North and Indian Mesa Power

	Partners, LP (Generator). These two agreements provide for the interconnection of WTU, now AEP Texas North's transmission system to the Generator's electric generating facilities (Plant) built in two (2) phases. The interconnection of each phase of the Plant is provided by the separate agreements.
ELECTRIC TRANSMISSION TEXAS SERVICE AGREEMENT	This agreement, dated December 21, 2007 is between Electric Transmission Texas (ETT) and AEPSC. This agreement covers the provision of services by AEPSC for ETT related to (i)the evaluation and permitting of electric transmission projects by ETT; (ii) budgeting and scheduling services, the preparation of construction documents, land acquisition services, engineering services, procurement services, construction services, and the compilation of project records, relating to the construction of electric transmission projects by ETT; (iii) operation and maintenance of its electric transmission projects; (iv) legal, human resources, environmental services, payroll, cash management, financial, billing, collection, accounts-payable, risk management, regulatory affairs, accounting, tax, and other business functions.
PATH WEST VIRGINIA TRANSMISSION COMPANY SERVICE AGREEMENT	This agreement, dated September 1, 2007 PATH) is between PATH West Virginia Transmission Company, LLC and AEP T&D Services, LLC. This agreement covers the provision of services by AEP T&D Services, LLC for PATH relating to designing, engineering, siting, acquiring right-of-way for procuring,

permitting, construction, commissioning, financing, owning, operating, and maintaining certain electric transmission and interconnection facilities.

SUMMARY

AEP System affiliates acquire coal for and provide for transporting coal to AEP's regulated utilities. With respect to certain affiliated power plants, AEP System affiliates may provide coal mining, coal preparation and/or coal transloading services.

COAL MINING (including lignite)

The following table lists the mining agreements between AEP's electric utilities and their mining subsidiaries:

DATE	***PARTIES***
05-31-01	Southwestern Electric Power Company and Dolet Hills Lignite Company LLC.

This agreement provides that the above mentioned mining company agree to mine, extract, remove, prepare and sell the coal or lignite they mine from their lands and, in some cases, from lands owned by the electric utility. The electric utility, in turn, agrees to purchase the coal and lignite. Certain AEP mines have been closed but continue to incur mine shutdown costs.

COAL TRANSPORTATION

There are several contracts under which AEP's electric utilities receive coal transportation services from affiliates.

BARGE TRANSPORTATION

The Barge Transportation Agreement, dated May 1, 1986 and amended September 12, 2013, is among Appalachian Power Company, Ohio Power Company, AEP Generating Company and Kentucky Power Company (Shippers) and the River Transportation Division of Indiana Michigan Power Company (Division).

This agreement provides for the Shippers to furnish and deliver coal to the Division at loading points along certain rivers and to accept delivery of such coal at designated delivery points and pay for the services of the Division in receiving, transporting and delivering such coal.

COAL TRANSFER-COOK COAL TERMINAL

The Amended and Restated Cook Coal Transfer Agreement – Cook Coal Terminal, dated December 16, 2013, is between AEP Generating Company (Operator) and Ohio Power Company, Indiana Michigan Power Company, Kentucky Power Company and Appalachian Power Company (Users).

This agreement provides for the Operator to unload coal for the Users from unit trains, transfer such coal from the unloading point at the terminal, re-load such coal on barges, and perform other related services at the terminal.

RAIL CAR USE

The AEP System Rail Car Use Agreement, dated April 1, 1982, is among Indiana Michigan Power Company, Appalachian Power Company and Ohio Power Company. It was amended effective July 1, 2006 to add Public Service Company of Oklahoma and Southwestern Electric Power Company as parties to the agreement. It was amended again effective September 12, 2013 to add Kentucky Power Company as a party to the agreement.

This agreement provides that coal hopper cars leased or otherwise deployed by the above parties be made available for the mutual benefit of each party without regard to lease ownership by a specific party but on the basis of proximity and availability for use, and other dispatching considerations.

RAILCAR MAINTENANCE

The Rail Car Maintenance Agreement, dated August 1, 2013, is among AEP Generating Company (Provider), Ohio Power

Company, Appalachian Power Company, Kentucky Power Company, Public Service of Oklahoma Southwestern Electric Power Company and Indiana Michigan Power Company.

This agreement provides for AEP Generating Company to furnish routine, preventive and other maintenance to the railroad hopper cars owned or leased by Appalachian Power Company, Kentucky Power Company, Public Service of Oklahoma Southwestern Electric Power Company and Indiana Michigan Power Company.

The Rail Car Maintenance Facility Agreement, dated July 29, 1997, is among SWEPCO, CPL, now AEP Texas Central, PSO.

A unit train rail car maintenance facility near Alliance, Nebraska has been established. SWEPCO is the majority owner and operates the facility. The actual cost of inspection and maintenance of individual rail cars and other expenses directly assignable to a specific rail car shall be paid by the party owning the rail car. Non-assignable costs are shared based on the direct labor charges for rail cars actually repaired or inspected per party in ratio to the total direct labor charges for all cars owned by the parties repaired at the facility during the month.

AMERICAN ELECTRIC POWER

Document Number **04-02-04**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
CONSULTING SERVICES

SUMMARY

This document identifies the consulting services agreements AEP's regulated utilities have with certain non-regulated affiliates.

AEP PRO SERV, INC. formerly AEP Resources Service Company, AEP Resources Engineering & Services Company and AEP Energy Services, Inc.)

The following table lists the consulting agreements between the AEP electric utilities and AEP Pro Serv, Inc. referred to as the "Client". These agreements allow the Client to utilize certain services, properties and resources of the AEP electric utilities to sell management, technical and training services and expertise to non-affiliate companies.

DATE	PARTIES
04-08-1983	Indiana Michigan Power Company and AEP Pro Serv, Inc.
04-08-1983	Ohio Power Company and AEP Pro Serv, Inc.
07-07-1983	Kingsport Power Company and AEP Pro Serv, Inc.
07-07-1983	Kentucky Power Company and AEP Pro Serv, Inc.
10-03-1983	Appalachian Power Company and AEP Pro Serv, Inc.
10-03-1983	Wheeling Electric Company and AEP Pro Serv, Inc.

AEP ENERGY SERVICES, INC. (formerly AEP Energy Solutions, Inc.)

The table which starts on the next page lists the consulting agreements between the AEP electric utilities and AEP Energy Services, Inc. (Client). These agreements allow the Client to utilize certain services, properties and resources of the electric utilities to broker and market energy commodities.

AMERICAN ELECTRIC POWER

Document Number **04-02-04**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
CONSULTING SERVICES

DATE	PARTIES
09-27-1996	Ohio Power Company and AEP Energy Services, Inc.
09-27-1996	Kingsport Power Company and AEP Energy Services, Inc.
09-27-1996	Kentucky Power Company and AEP Energy Services, Inc.
09-27-1996	Indiana Michigan Electric Company and AEP Energy Services, Inc.
01-09-1997	Wheeling Power Company and AEP Energy Services, Inc.
03-06-1997	Appalachian Power Company and AEP Energy Services, Inc.

SUMMARY

The Philip Sporn Plant, Mitchell Plant and certain other AEP facilities are jointly owned and operated.

PHILIP SPORN PLANT AGREEMENT

The Sporn Plant Operating Agreement, dated January 1, 2014, is between Appalachian Power Company and AEP Generation Resources Inc. (“Owners”) and American Electric Power Service Corporation (“Agent”).

Appalachian Power Company owns two 150,000 kilowatt generating units (Sporn units Nos. 1 and 3) and AEP Generation Resources Inc. owns two 150,000 kilowatt generating units Sporn units 2 and 4). The Owners desire that Appalachian Power Company operate and maintain Philip Sporn Plant.

MITCHELL PLANT

The Mitchell Plant Operating Agreement, dated January 1, 2014, is between Kentucky Power Company and AEP Generation Resources Inc. (“Owners”) and American Electric Power Service Corporation (“Agent”).

Kentucky Power Company and AEP Generation Resources have an undivided ownership interest in Mitchell Plant which consists of two 800 megawatt generating units The Owners desire that Kentucky Power Company operate and maintain Mitchell Plant.

KAMMER PLANT AGREEMENT

The Kammer Plant Operating Agreement, dated January 1, 2014, is between Kentucky Power Company (“Operator”) and AEP Generation Resources Inc. (“Owner”) and American Electric Power Service Corporation (“Agent”).

AEP Generation Resources owns Kammer Plant which consists of three 210 megawatt generating units The Owner desires that Kentucky Power Company operate and maintain

	Kammer Plant.
EAST HVDC INTERCONNECTION AGREEMENT	This agreement, August 3, 1995, is among Southwestern Electric Power Company, CSW, now AEP Texas Central, Houston Lighting and Power Company (now Reliant Energy, HLP) and Texas Utilities Electric Company
	This agreement covers certain high voltage direct current (HVDC) conversion and related alternating current transmission defined as the HVDC Interconnection located in Titus
EAST HVDC INTERCONNECTION AGREEMENT (Cont’d)	SWEPCO operates the facility. It owns certain of the alternating current facilities and charges the other partici-pants a facility charge based on their ownership interest in the HVDC Project. SWEPCO also bills operational and maintenance charges it incurs as the operator based on ownership interest.
OKLAUNION UNIT NO.1 CONSTRUCTION, OWNERSHIP AND OPERATING AGREEMENT (Also known as the Participation Agreement)	This agreement, dated April 26, 1985 an amended on August 14, 1985) is among Public Service Company of Oklahoma, AEP Texas North and and the Oklahoma Municipal Power and the City of Brownsville, Texas.
	The Oklaunion Power Unit No. 1 is a 720 MW western coal fired steam generator. It is located on 1937.2 acres in Wilbarger County, Texas. This agreement is for the construction, ownership and operation of Oklaunion Power Unit 1.
OKLAUNION HVDC PROJECT CONSTRUCTION, OWNERSHIP AND OPERATING AGREEMENT	This agreement, dated September 14,1988, is among PSO, AEP Texas North Company and Central and South West Services, Inc.
	PSO and WTU own, and operate the project known as the Oklaunion HVDC Tie located in Wilbarger County, Texas.

AMERICAN ELECTRIC POWER

Document Number **04-02-06**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
TAX AGREEMENT

SUMMARY

American Electric Power Company, Inc. (AEP) joins in filing a consolidated federal income tax return with its affiliates in the AEP holding company system.

TAX AGREEMENT

The AEP System tax agreement, among other things, sets forth the companies' agreement to annually join in the filing of a consolidated federal income tax return and the method under which to allocate the consolidated tax to the system companies. This agreement permits the allocation of the benefit of current tax losses utilized to the System companies giving rise to them in determining their current tax expense.

The tax loss of AEP is allocated to its subsidiaries with taxable income. With the exception of the loss of AEP, the method of allocation approximates a separate return result for each company in the consolidated group.

SUMMARY	The AEP System Utility Money Pool Agreement is an arrangement whereby the participants in the Utility Money Pool lend to and borrow from each other on a short-term basis.
DESCRIPTION	The AEP System Amended and Restated Money Pool Agreement, dated November 14, 2013,is among and between AEP, AEP Utilities, Inc., American Electric Power Service Corporation, and AEP Utility Funding LLC and regulated direct and indirect operating and certain other subsidiaries each of which are signatories to the Agreement or have become signatories.
	The Agreement gives participants the right to borrow from the pool and invest their excess funds in the pool.
	A further description of the Utility Money Pool is contained in another section of this manual (see the Table of Contents or the Alphabetic Subject Index to find the applicable Document Number).

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
AEP SYSTEM AMENDED AND RESTATED NONUTILITY MONEY POOL AGREEMENT

SUMMARY

The AEP System Nonutility Money Pool Agreement is an arrangement whereby the participants in the Nonutility Money Pool lend to and borrow from each other on a short-term basis.

DESCRIPTION OF THE AGREEMENT

The AEP System Third Amended and Restated Nonutility Money Pool Agreement, dated May 1, 2012, is between AEP, and American Electric Power Service Corp., AEP Nonutility Funding LLC certain and unregulated direct and indirect subsidiaries of AEP each of which are signatories to the Agreement or have become signatories.

The Agreement gives each pool participant the right to borrow from the pool and to invest excess funds in the pool.

A further description of the Nonutility Money Pool is contained in another section of this manual (see the Table of Contents or the Alphabetic Subject Index to find the applicable Document Number).

SUMMARY	Certain databases have been established for employee reference purposes.
CHARTFIELD VALUES	A separate Lotus Notes database can be used to view certain chartfield values. The chartfield database contains the most current information regarding the various chartfield values and descriptions.

04-03-02

AFFLIATE AGREEMENTS	Copies of all agreements between AEP regulated utilities and their affiliates are kept in Company files.

04-03-03

AEP AMERICAN ELECTRIC POWER

Document Number **04-03-02**

Cost Allocation Manual

Section

Databases

Subject

CHARTFIELD VALUES

SUMMARY

Several chartfield databases have been established for employee reference purposes. A Lotus Notes database link provides a menu for accessing the separate databases. The chartfield databases contain the most current information regarding the various chartfield values and descriptions.

INSTRUCTIONS FOR DESKTOP INSTALLATION

To add the Chartfields icon to your Lotus Notes Desktop, you will need to perform the following steps:

1. Enter Lotus Notes.
2. Hold the Ctrl button while pressing the letter "o".
3. Select the proper Server for your location by using the down arrow, or type and hit enter. Some of the available servers include:

   DSAPP4OR/SERVERS/AEPIN Columbus
   DSAPP1FW/SERVERS/AEPIN Canton, Charleston, Fort Wayne
   DSAPP1RO/SERVERS/AEPIN Roanoke

4. Using the Database section, select the DATABASE folder (not Database catalog)

   a. Select FINANCE
   b. Select CORPPLAN
   c. Select Chartfields Portfolio
   d. Click the Open button.

INSTRUCTIONS FOR VIEWING

Once the database link icon has been added to your desktop, the chartfield values may be viewed by clicking on the database that contains the value(s) you are looking for: GL Business Unit, Account, Department, State/Jurisdiction, Product, ABM Activity (Resource Category), Cost Component, Resource Sub Category (or Tracking Code), Benefiting

Location, AEPSC Work Order, UT Work Order, and NR Work Order.

AMERICAN ELECTRIC POWER

Document Number **04-03-03**

Cost Allocation Manual

Section

Databases

Subject

AFFILIATE AGREEMENTS

SUMMARY

An affiliated contracts database has been established for reference purposes. A Lotus Notes database link provides a method for accessing this database. The affiliated contracts database contains copies of the affiliated contracts.

INSTRUCTIONS FOR DESKTOP INSTALLATION

To add the Affiliated Contracts to your Lotus Notes Desktop, you will need to perform the following steps:

1. Enter Lotus Notes/Workspace at Office.
2. Click on Database Catalog (DSAPP1RO) icon.
3. From the Database Catalog Menu, click Databases (By Title).
4. Click Affiliate Transactions once and its subtitle twice to access the Affiliated Contracts index.

INSTRUCTIONS FOR VIEWING

To view the appropriate affiliate contract, double click on the name of the contract.

SECURITY ACCESS

The CAM Administrator grants access to this database on an as needed basis.

AMERICAN ELECTRIC POWER

Document Number **04-04-01**

Cost Allocation Manual

Section

Job Descriptions

Subject

OVERVIEW

SUMMARY

The corporate separation rules adopted by the Public Utilities Commission of Ohio (PUCO) require the electric utility, as defined in the rules, to maintain a copy of each shared employee's job description in its Cost Allocation Manual (CAM). In addition, the CAM shall include a copy of all transferred employees' previous and new job descriptions.

The corporate separation rules define "employees" as "all full-time or part-time employees of an electric utility or its affiliates, as well as consultants, independent contractors or any other persons, performing various duties or obligations on behalf of or for an electric utility or its affiliates."

Job descriptions are not required, nor are they maintained, for consultants, independent contractors or any other persons who are not actual employees of the electric utility or its AEP affiliates.

SHARED EMPLOYEES

Job descriptions for all employees who are shared between AEP's PUCO regulated electric utilities and any affiliate that provides a competitive retail electric service, or that provides a non-electric product or service to customers, are incorporated in this manual by reference.

04-04-02

TRANSFERRED EMPLOYEES

The required previous and current job descriptions for employees transferred from AEP's PUCO regulated electric utilities to any affiliate that provides a competitive retail electric service, or that provides a non-electric product or service to

TRANSFERRED EMPLOYEES (Cont'd)

customers, are incorporated in this manual by reference.

O4-04-03

SUMMARY	4901:1-37-04 (A)(4) of the Public Utilities Commission of Ohio's (PUCO's) corporate separation rules states that an electric utility may not share employees and/or facilities with any affiliate, if the sharing, in any way, violates the code of conduct provisions contained in its corporate separation rules. In addition, 4901:1-37-08 (D)(4) and 4901:1-37-04 (A) (5) of the corporate separation rules require the electric utility to maintain a copy of each shared employee's job description in its Cost Allocation Manual and to ensure that all shared employees appropriately record and charge their time based on fully allocated costs.
DEFINITION OF SHARED EMPLOYEE	In the corporate separation plans filed by Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011) (Case No. 99-1730-EL-ETP), the respondents defined a "shared employee" as: *Any employee of the electric utility, or any affiliate which provides a competitive retail electric service or which provides a non-electric product or service to customers (i.e., the Separate AEP Companies), or a consultant, independent contractor, or any other person performing various duties or obligations on behalf of the electric utility or the Separate AEP Companies, whose more than incidental job duties and responsibilities are divided between the electric utility and any Separate AEP Companies for other than emergency purposes.*
PROCEDURE	For purposes of this manual,job descriptions for shared employees who are true employees of the electric utility or any Separate AEP

PROCEDURE (Cont'd)	Company are included in this manual by reference and, as such, are part of this manual. Job descriptions are not maintained for consultants, independent contractors or other persons who are shared but are not actual employees of the electric utility or the Separate AEP Companies. However, a list of such persons will be maintained. The list will identify the name of each such person and the name of the person's actual employer. The list, which will be prepared at least every six months, is incorporated in this manual by reference and, as such, is part of this manual.
RESPONSIBILITY	AEP Service Corporation's Human Resources Department, working with AEP's various business units, will prepare, on behalf of AEP's PUCO regulated electric utilities, the required job descriptions for all shared employees; and it will also maintain the required list of other shared persons who are not actual employees.
TIME CHARGES	AEP's time reporting systems are designed to ensure that salary and salary-related costs are properly allocated by requiring employees, using positive time reporting, to charge their time to the appropriate accounting codes. All time charges are allocated and billed on a fully allocated cost basis as defined in the PUCO's Corporate Separation rules. *[NOTE: Other state commissions have established requirements relative to shared employees. See TAB 02, Section 04 of this manual for further information.]*

AEP AMERICAN ELECTRIC POWER

Document Number **04-04-03**

Cost Allocation Manual

Section

Job Descriptions

Subject

TRANSFERRED EMPLOYEES (PUCO)

SUMMARY

4901:1-37-08 (D)(6) of the Public Utilities Commission of Ohio's (PUCO's) corporate separation rules require electric utilities, as defined in the rules, to add to their Cost Allocation Manuals (CAMs) a copy of all transferred employees' previous and new job descriptions.

DEFINITION OF TRANSFERRED EMPLOYEE

A "transferred employee" is any full-time or part-time employee of the electric utility, as well as any consultant, independent contractor or any other person, who performs various duties or obligations for or on behalf of the electric utility, that transfers from the electric utility to any affiliate which provides a competitive retail electric service or which provides a non-electric product or service to customers (i.e., the Separate AEP Companies).

PROCEDURE

For purposes of this manual, previous and new job descriptions for all true employees of the electric utility that transfer to a Separate AEP Company are included in this manual by reference and, as such, are part of this manual.

Job descriptions are not maintained for consultants, independent contractors or other persons who are not true employees of the AEP System. However, a list of all such persons who transfer from the electric utility to a Separate AEP Company will be maintained. The list will identify the name of each such person and the name of the person's actual employer. The list, which will be prepared at least every six months, is incorporated in this manual by reference and, as such, is part of this manual.

AMERICAN ELECTRIC POWER

Document Number **04-04-03**

Cost Allocation Manual

Section

Job Descriptions

Subject

TRANSFERRED EMPLOYEES (PUCO)

RESPONSIBILITY

AEP Service Corporation's Human Resources Department, working with AEP's various business units, will prepare, on behalf of any AEP electric utility regulated by the PUCO, the required job descriptions for all employees who transfer from the electric utility to a Separate AEP company. Human Resources will also maintain the required list of other transferred persons who are not actual employees of the AEP System.

[NOTE: Other state commissions have established requirements relative to transferred employees. See TAB 02, Section 04 of this manual for further information.]

SUMMARY	The corporate separation rules adopted by the Public Utilities Commission of Ohio require Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011) to establish a complaint procedure for issues related to their respective corporate separation plans.
COMPLAINT LOG	A log of complaints brought to the electric utility must be maintained as part of the electric utility’s Cost Allocation Manual.

04-05-02

SUMMARY	4901:1-37-05 (B) (14) and 4901:1-37-08 (D)(8) of the Public Utilities Commission of Ohio’s (the PUCO’s) corporate separation rules require the electric utilities, as defined in the rules, to establish a complaint procedure for issues concerning compliance with the PUCO’s corporate separation rules and a log of complaints brought to the utility to be included in its CAM.
RESPONSIBILITY	AEP’s Chief Compliance Officer will follow the procedures for handling such complaints as set forth in the PUCO’s rules and as stated in the corporate separation plans filed by Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011) and Ohio Power Company.
CAM REQUIREMENTS	The required complaint log is incorporated in this manual by reference and, as such, is part of this manual.

SUMMARY	The corporate separation rules adopted by the Public Utilities Commission of Ohio (PUCO) require Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011), or any successor electric utility company operating in the state of Ohio, to incorporate a copy of the minutes of each of their board of directors meetings in their Cost Allocation Manual (CAM).
COPIES	The required minutes are incorporated in this manual by reference.

04-06-02

SUMMARY	4901:1-37-08(D)(9) of the PUCO's corporate separation rules require electric utilities to incorporate their minutes of each board of directors meeting in their Cost Allocation Manual (CAM) as a structural safeguard for a minimum period of three years.
RESPONSIBILITY	AEP's Legal Department maintains the required minutes as described in the corporate separation plans filed by Columbus Southern Power Company (Which was merged into Ohio Power Company effective December 31, 2011) and Ohio Power Company.
CAM REQUIREMENTS	The required minutes are incorporated in this manual by reference and, as such, are part of this manual.

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Document Number **04-07-01**

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Tariff Provisions

Subject

Overview

SUMMARY

The corporate separation rules adopted by the Public Utilities Commission of Ohio requires Ohio Power Company to establish a procedure detailing each instance in which the electric utility exercised discretion in the application of its tariff provisions.

TARIFF DISCRETION LOG

A log detailing each instance when the electric utility exercised discretion in application of its tariff provisions must be maintained as part of the electric utility's Cost Allocation Manual.

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Document Number **04-07-02**

Cost Allocation Manual

Section

Tariff Provisions

Subject

SUMMARY

4901:1-37-08 (D) (7) of the Public Utilities Commission of Ohio’s (the PUCO’s) corporate separation rules require the electric utilities, as defined in the rules, to establish a procedure detailing each instance in which the electric utility exercised discretion in the application of its tariff provisions and a log of such instances to be included in its CAM.

RESPONSIBILITY

AEP Ohio’s VP of Regulatory and Finance maintains the required procedure and related Tariff Discretion Log.

CAM REQUIREMENTS

The required log is incorporated in this manual by reference and, as such, is part of this manual.

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Document Number **99-00-01**

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Appendix

Subject

OVERVIEW (APPENDIX)

SUMMARY	This appendix contains tables and other supplementary information that can be used for reference purposes.
GLOSSARY OF KEY TERMS	A glossary of key terms and acronyms is provided to assist the reader.
	99-00-02
RECORD RETENTION REQUIREMENTS	A summary of the record retention requirements prescribed by AEP's various commissions for transactions with affiliates is maintained as part of this manual.
	99-00-03
LIST OF APPROVED ALLOCATION FACTORS	An Allocation Factor defines the factor(s) that will be used to derive the percentages of cost to be billed to each company whenever costs are shared among AEP System companies through the billing process. A list of approved Allocation Factors is maintained as part of this manual.
	99-00-04
LIST OF PRIMARY ALLOCATION FACTORS BY FUNCTION	Allocation Factors are assigned to final cost objectives generally based on the nature (i.e., function) of the work performed. A list of the primary Allocation Factors for each function is maintained as part of this manual.
	99-00-05
LIST OF AFFILIATE CONTRACTS BY COMPANY	AEP's regulated utilities have entered into various agreements with their affiliates. **TAB** 04, Section 02 of this manual contains

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OVERVIEW (APPENDIX)

LIST OF AFFILIATE CONTRACTS BY COMPANY (Cont'd)

a description of each contract.

A list of the various contracts with each regulated utility is maintained as part of this manual.

99-00-06

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GLOSSARY OF KEY TERMS

SUMMARY

This glossary provides definitions for key terms and abbreviations used in this manual. Unless the context in which the terms and abbreviations as used in this manual clearly indicate a different meaning as indicated in this glossary.

AEP American Electric Power Company, Inc.

AEPSC American Electric Power Service Corporation

AEP holding company system American Electric Power Company, Inc. (parent holding company) together with all of its subsidiaries.

AEP System The electric utility companies, subsidiaries of American Electric Power Company, Inc. together with their subsidiary coal-mining and power generating companies as well as AEPSC.

Affiliates While each regulatory commission has its own unique definition of the term "affiliates," as used in this manual the term generally includes American Electric Power Company, Inc. and all companies that are owned or controlled by American Electric Power Company, Inc.

Affiliate transactions Transactions between or among affiliates for the sale and purchase of products, services and capital assets.

Allocation Factors The cost allocation methods, factors and percentages used in the billing process to allocate costs among AEP companies.

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Chartfields (or coding blocks)	The distinctive fields used to affix codes to transaction records generally for the purpose of identification, classification and retrieval.
Common costs	Costs that benefit both regulated and non-regulated products and services. Also see, **Joint costs**.
Cost allocator	The method or ratio used to apportion cost. A cost allocator can be based on the origin of costs, as in the case of cost drivers; cost-causative linkage of an indirect nature; or one or more overall factors (also known as general allocators).
Cost driver	A measurable event or quantity which influences the level of cost incurred and which can be directly traced to the origin of the costs themselves.
Primary cost driver	The dominant driver of a given cost or cost pool.
Cross-subsidy	The amount of cost recovered from one class of customers or business unit that is attributable to another.
Direct costs	Costs that can be identified specifically with a given cost objective.
FERC	Federal Energy Regulatory Commission.
Fully-allocated costs (or fully-distributed costs)	Direct costs plus an appropriate share of indirect costs attributed to a given cost objective.
General allocator	See **Cost allocator**.
Indirect costs	Costs that cannot be identified specifically

	with a given cost objective. Indirect costs include, but are not limited to overhead costs, and some taxes.
Joint costs	Costs that benefit two or more cost objectives.
Non-regulated operations	Activities which produce products or services that are not subject to price regulation by regulatory authorities.
Regulated operations	Activities which produce products or services that are subject to price regulation by government authorities.
SEC	Securities and Exchange Commission.
Shareable costs	Costs that are billable to two or more companies (affiliated and non-affiliated) by mutual agreement using fixed or variable percentages.
Transfer pricing	The price or method used to transfer (or bill for) products or services delivered by one division of a company to another division, or by one affiliate to another affiliate. Transfer pricing also pertains to asset transfers and sales.
USoA	The Uniform System of Accounts adopted by each regulatory commission (usually the Uniform System of Accounts prescribed by the FERC for public utilities and licensees subject to the provisions of the Federal Power Act).

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Subject

RECORD RETENTION REQUIREMENTS

SUMMARY

Some of AEP's commissions have prescribed minimum record retention requirements for those records that are specifically related to transactions with certain affiliates.

ARKANSAS

Arkansas Rule 4.04 requires an electric utility to maintain a record of all transactions with its competitive affiliates for at least three years following the date of each transaction.

Arkansas requirements can be found in Arkansas Public Service Commission Order 7 of Docket 06-112-R, dated May 25, 2007.

LOUISIANA

As prescribed in the Louisiana Merger Stipulation Appendix A – Affiliate Transaction Conditions 13, SWEPCO or AEPSC on behalf of SWEPCO may not make any non-emergency procurement in excess of $1 million per transaction from an unregulated affiliate other than from AEPSC except through a competitive bidding process or as otherwise authorized by this Commission. Transactions involving the Company and CSW Credit, Inc. (or its successor) for the financing of accounts receivables are exempt from this condition. Records of all such affiliate transactions must be maintained until the Company's next comprehensive retail review. In addition, at the time of the next comprehensive rate review, all such affiliate transactions that were not competitively bid shall be separately identified for the Commission by the Company. This identification shall include all transactions between the Company and AEPSC in which AEPSC acquired the goods or services from another unregulated affiliate.

OHIO

The corporate separation rules adopted by the Public Utilities Commission of Ohio (PUCO) contain a minimum retention period of three years for all information relative to transactions between the electric utility and its affiliates [4901:1-37-08(G].

As prescribed by the PUCO, all of AEP's Ohio-based electric utilities and their affiliates shall maintain all underlying affiliate transaction information for a minimum of five years.

OKLAHOMA

The Oklahoma Corporation Commission rules require utility to keep records in the form and for a period of time not less than that specified by the applicable rules of FERC or the RUS; or in the absence thereof, for two (2) years. [Chapter 165:35-1-4(a)].

TEXAS

The code of conduct rules adopted by the Public Utility Commission of Texas require the utility to maintain a contemporaneous written record of all transactions with its competitive affiliates, except those involving corporate support services (as defined in the rules) and those transactions governed by tariff. Such records shall be maintained by the utility for three years [§25.272(e)(1)].

The same three-year minimum retention period also applies to the records that are required to be maintained in connection with any discounts, rebates, fee waivers, or alternative tariff terms and conditions offered or granted by the utility to its competitive affiliates for any product or service. In addition, the utility is required to make such records available for third party review within 72 hours of a written request, or at a time mutually

TEXAS (Cont'd)

agreeable to the utility and the third party [§25.272(f)(2)].

A competitive affiliate is an affiliate that provides services or sells products in a competitive energy-related market in Texas, including telecommunications services; to the extent those services are energy-related.

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LIST OF FERC ACCEPTED ALLOCATION FACTORS

SUMMARY

The following table provides a complete list of approved Allocation Factors along with a description of the numerator and the denominator applicable to each calculation.

NO.	ALLOCATION FACTORS	NUMERATOR/DENOMINATOR	UPDATED
01	Number of Bank Accounts	Number of Bank Accounts by Company Total Number of Bank Accounts	Inactive
02	Number of Call Center Telephones	Number of Call Center Phone Calls Per Company Total Number of Call Center Telephones	Inactive
03	Number of Cell Phones/Pagers	Number of Cell Phones/Pagers Per Company Total Number of Cell Phones/Pagers	Quarterly
04	Number of Checks Printed	Number of Checks Printed Per Company Per Month Total Number of Checks Printed Per Month	Inactive
05	Number of CIS Customer Mailings	Number of Customer Information System (CIS) Customer Mailings Per Company Total Number of CIS Customer Mailings	Monthly
06	Number of Commercial Customers	Number of Commercial Customers Per Company Total Number of Commercial Customers	Semi-Annually
07	Number of Credit Cards	Number of Credit Cards Per Company Total Number of Credit Cards Number of Commercial	Inactive
08	Number of Electric Retail Customers	Number of Electric Retail Customers Per Company Total Number of Electric Retail Customers	Semi-Annually
09	Number of Employees	Number of Full-Time and Part-Time Employees Per Company Total Number of Full-Time and Part-Time Employees	Monthly
10	Number of Generating Plant Employees	Number of Generating Plant Employees Per Company Total Number of Generating Plant Employees	Inactive
11	Number of General Ledger(GL) Transactions	Number of GL Transactions Per Company Total Number of GL Transactions	Monthly
12	Number of Help Desk Calls	Number of Help Desk Calls Per Company Total Number of Help Desk Calls	Monthly
13	Number of Industrial Customers	Number of Industrial Customers Per Company Total Number of Industrial Customers	Semi-Annually

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LIST OF FERC ACCEPTED ALLOCATION FACTORS

14	Number of JCA Transactions	Number of Lines of Accounting Distribution on Job Cost Accounting (JCA) Sub-System Per Company / Total Number of Lines of Accounting Distribution on JCA Sub-System	Inactive
15	Number of Non-UMWA Employees	Number of Non-UMWA or All Non-Union Employees Per Company / Total Number of Non-UMWA or All Non-Union Employees	Monthly
16	Number of Phone Center Calls	Number of Phone Calls Per Phone Center Per Company / Total Number of Phone Center Phone Calls	Monthly
17	Number of Purchase Orders Written	Number of Purchase Orders Written Per Company / Total Number of Purchase Orders Written	Monthly
18	Number of Radios (Base/Mobile/Handheld)	Number of Radios (Base/Mobile/Handheld) Per Company / Total Number of Radios (Base/Mobile/ Handheld)	Semi-Annually
19	Number of Railcars	Number of Railcars Per Company / Total Number of Railcars	Annually
20	Number of Remittance Items	Number of Electric Bill Payments Processed Per Company Per Month (non-lockbox) / Total Number of Electric Bill Payments Processed Per Month (non-lockbox)	Monthly
21	Number of Remote Terminal Units	Number of Remote Terminal Units Per Company / Total Number of Remote Terminal Units	Annually
22	Number of Rented Water Heaters	Number of Rented Water Heaters Per Company / Total Number of Rented Water Heaters	Inactive
23	Number of Residential Customers	Number of Residential Customers Per Company / Total Number of Residential Customers	Semi-Annually
24	Number of Routers	Number or Routers Per Company / Total Number of Routers	Inactive
25	Number of Servers	Number of Servers Per Company / Total Number of Servers	Inactive
26	Number of Stores Transactions	Number of Stores Transactions Per Company / Total Number of Stores Transactions	Monthly
27	Number of Telephones	Number of Telephones Per Company (Includes all phone lines) / Total Number of Telephones (Includes all phone lines)	Semi-Annually

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LIST OF FERC ACCEPTED ALLOCATION FACTORS

28	Number of Transmission Pole Miles	Number of Transmission Pole Miles Per Company Total Number of Transmission Pole Miles	Annually
29	Number of Transtext Customers	Number of Expected Transtext Customers Per Company Total Number of Expected Transtext Customers	Inactive
30	Number of Travel Transactions	Number of Travel Transactions Per Company Per Month Total Number of Travel Transactions Per Month	Monthly
31	Number of Vehicles	Number of Vehicles Per Company Includes Fleet and Pool Cars) Total Number of Vehicles Per Company (Includes Fleet and Pool Cars)	Annually
32	Number of Vendor Invoice Payments	Number of Vendor Invoice Payments Per Company Per Month Total Number of Vendor Invoice Payments Per Month	Monthly
33	Number of Workstations	Number of Workstations (PCs) Per Company Total Number of Workstations (PCs)	Quarterly
34	Active Owned or Leased Communication Channels	Number of Active Owned/Leased Communication Channels Per Company Total Number of Active Owned/Leased Communication Channels	Inactive
35	Avg Peak Load For Past Three Years	Average Peak Load for Past Three Years Per Company Total of Average Peak Load for Past Three Years	Inactive
36	Coal Company Combination	The Sum of Each Coal Company's Gross Payroll, Original Cost of Fixed Assets, Original Cost of Leased Assets, and Gross Revenues for Last Twelve Months The Sum of the Same Factors for All Coal Companies	Inactive
37	AEPSC Past 3 Months Total Bill Dollars	AEPSC Past Three Months Total Bill Dollars Per Company Total AEPSC Past Three Months Bill Dollars	Monthly
38	AEPSC Prior Month Total Bill Dollars	Total Bill Dollars AEPSC Prior Month Per Company AEPSC Total Prior Month Bill Dollars	Monthly
39	Direct	100% to One Company	Monthly
40	Equal Share Ratio	One Company (1) Total Number of Companies	Monthly

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41	Fossil Plant Combination	The Sum of (a) the Percentage Derived by Dividing the Total Megawatt Capability of All Fossil Generating Plants Per Company by the Total Megawatt Capability of All Fossil Generating Plants and (b) the Percentage Derived by Dividing the Total Scheduled Maintenance Outages of All Fossil Generating Plants Per Company for the Last Three Years by the total Scheduled Maintenance of All Fossil Generating Plants During the Same Three Years Two (2)	Inactive
42	Functional Department's Past 3 Months Total Bill Dollars	Functional Department's Past 3 Months Total Bill Dollars Per Company Total Functional Department's Past 3 Months Total Bill Dollars	Inactive
43	KWH Sales	KWH Sales Per Company Total KWH Sales	Annually
44	Level of Construction – Distribution	Construction Expenditures for All Distribution Plant Accounts Except Land and Land Rights, Services, Meters and Leased Property on Customers Premises, and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC Are Being Made Separately, Per Company/During the Last Twelve Months Total of the Same for All Companies	Semi-Annually
45	Level of Construction - Production	Construction Expenditures for All Production Plant Accounts Except Land and Land Rights, Nuclear Accounts, and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, Per Company During the Last Twelve Months Total of the Same for All Companies	Semi-Annually
46	Level of Construction – Transmission	Construction Expenditures for All Transmission Plant Accounts Except Land and Land Rights and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, Per Company During the Last Three Months Total of the Same for All Companies	Quarterly

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47	Level of Construction – Total	Construction Expenditures for All Plant Accounts Except Land and Land Rights, Line Transformers Services, Meters and Leased Property on Customers' premises; and the Following General Plant Accounts: Structures and Improvements, Shop Equipment, Laboratory Equipment and Communication Equipment; and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, Per Company During the Last Twelve Months / Total of the Same for All Companies	Inactive
48	MW Generating Capability	MW Generating Capability Per Company / Total MW Generating Capability	Annually
49	MWH's Generated	Number of MWH's Generated Per Company / Total Number of MWH's Generated	Semi-Annually
50	Current Year Budgeted Salary Dollars	Current Year Budgeted AEPSC Payroll Dollars Billed Per Company / Total Current Year Budgeted AEPSC Payroll Dollars Billed	Inactive
51	Past 3 Mo. MMBTU's Burned (All Fuel Types)	Past Three Months MMBTU's Burned Per Company (All Fuel Types) / Total Past Three Months MMBTU's Burned (All Fuel Types)	Quarterly
52	Past 3 Mo. MMBTU's Burned (Coal Only)	Past Three Months MMBTU's Burned Per Company (Coal Only) / Total Past Three Months MMBTU's Burned (Coal Only)	Quarterly
53	Past 3 Mo. MMBTU's Burned (Gas Type Only)	Past Three Months MMBTU's Burned Per Company (Gas Type Only) / Total Past Three Months MMBTU's Burned (Gas Type Only)	Quarterly
54	Past 3 Mo. MMBTU's Burned (Oil Type Only)	Past Three Months MMBTU's Burned Per Company (Oil Type Only) / Total Past Three Months MMBTU's Burned (Oil Type Only)	Inactive
55	Past 3 Mo. MMBTU's Burned (Solid Fuels Only)	Past Three Months MMBTU's Burned Per Company (Solid Fuels Only / Total Past Three Months MMBTU's Burned (Solid Fuels Only)	Quarterly

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LIST OF FERC ACCEPTED ALLOCATION FACTORS

56	Peak Load/Avg # Cust/KWH Sales Combination	Average of Peak Load, # of Retail Customers, and KWH Sales to Retail Customers Per Company Total of Average of Peak Load, # of Retail Customers, and KWH Sales to Retail Customers	Inactive
57	Tons of Fuel Acquired	Number of Tons of Fuel Acquired Per Company Total Number of Tons of Fuel Acquired	Semi-Annually
58	Total Assets	Total Assets Amount Per Company Total Assets Amount	Quarterly
59	Total Assets Less Nuclear Plant	Total Assets Amount Less Nuclear Assets Per Company Total Assets Amount Less Nuclear Assets	Quarterly
60	Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or Other Indirect Costs	Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or Other Indirect Costs Per Company Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or Other Indirect Costs	Annually
61	Total Fixed Assets	Total Fixed Assets Amount Per Company Total Fixed Assets Amount	Quarterly
62	Total Gross Revenue	Total Gross Revenue Last Twelve Months Per Company Total Gross Revenue Last Twelve Months	Inactive
63	Total Gross Utility Plant (Including CWIP)	Total Gross Utility Plant Amount Per Company (Including CWIP) Total Gross Utility Plant Amount (Including CWIP)	Quarterly
64	Total Peak Load	Total Peak Load Per Company Total Peak Load	Monthly
65	Hydro MW Generating Capability	Hydro MW Generating Capability per Company Total Hydro MW Generating Capability	Annually
66	Number of Forest Acres	Number of Forest Acres Per Company Total Number of Forest Acres	Annually
67	Number of Banking Transactions	Number of Banking Transactions Per Company Total Number of Banking Transactions	Quarterly
68	Number of Dams	Number of Dams Per Company Total Number of Dams	Inactive

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LIST OF FERC ACCEPTED ALLOCATION FACTORS

69	Number of Licenses Obtained	Number of Licenses Obtained per Company / Total Number of Licenses	Inactive
70	Number of Non-Electric OAR Invoices	Number of Non-Electric OAR Invoices Per Company / Total Number of Non-Electric OAR Invoices	Semi-Annually
71	Number of Transformer Transactions	Number of Transformer Transactions Per Company / Total Number of Transformer Transactions	Monthly
72	Tons of FGD Material	Tons of FGD Material Per Company / Total Tons of FGD Material	Semi-Annually
73	Tons of Limestone Received	Tons of Limestone Received Per Company / Total Tons of Limestone Received	Semi-Annually
74	Total Assets/Total Revenues/Total Payroll	Total Assets + Total Revenues + Total Payroll Per Company / Total Assets + Total Revenues + Total Payroll	Inactive
75	Total Leased Assets	Total Leased Assets Per Company / Total Leased Assets	Inactive
76	Number of Banking Transactions	Number of Banking Transactions by Company / Total Number of Banking Transactions	Inactive
77	Power Transactions to All Markets	Power Transactions by Company / Total Number of Power Transactions	Monthly
78	Power Transactions to ERCOT Market	Power Transactions to ERCOT Market by Company / Total Number of Power Transactions to ERCOT Market	Monthly
79	Trans (commdts) to All Markets	Trans (commdts) to all Markets by Company / Total Number of Trans (commdts) to all Markets	Monthly
80	Trans (commdts) to ERCOT Market	Trans (commdts) to ERCOT Markets by Company / Total Number of Trans (commdts) to ERCOT Markets	Monthly

SUMMARY

The following table identifies the primary Allocation Factors that are associated with the listed functions.

GROUP/FUNCTION	***PRIMARY ALLOCATION FACTORS***
Audit Services	Total Assets, 100% to One Company, Number of Employees, AEPSC Past 3 Months Total Bill
Chief Administrative Officer Administration	Total Assets, 100% to One Company, Level of Construction – Transmission
Chief Executive Officer Administration	Total Assets, 100% to One Company, AEPSC Past 3 Months Total Bill
Chief Financial Officer Administration	Total Assets, 100% to One Company, AEPSC Past 3 Months Total Bill
Chief Operating Officer Administration	Total Assets,100% to One Company, Level of Construction – Distribution
Commercial Operations	Total Peak Load, MWH’s Generation, 100% to One Company
Corporate Accounting	Total Assets, 100% to One Company, Number of GL Transactions
Corporate Communications	Number of Employees, Total Assets, AEPSC Past 3 Months Total Bill
Corporate Human Resources	Number of Employees, 100% to One Company, Total Assets
Corporate Planning and Budgeting	Total Assets, Number of Electric Retail Customers, MW Generating Capacity
Customer & Dist Services	100% to One Company, Number of Electric Retail Customers, Number of CIS Customer Mailings, Number of Phone Center Calls
Electric Transmission Texas	100% to One Company, Level of Construction – Transmission, Past 3 Months Total Bill
Environment and Safety	100% to One Company, MW Generating Capability, Total Assets, Number of Employees
Ethics and Compliance	Number of Employees, AEPSC Bill less Indir & Int, Past 3 Months Total Bill
Federal Affairs	Total Assets, 100% to One Company, Number of Electric Retail Customers
Fossil & Hydro Generation	100% to One Company, Total Assets,

GROUP/FUNCTION	***PRIMARY ALLOCATION FACTORS***
	MW Generating Capability, MWH’s Generation
Fuel, Emissions & Logistics	Tons of Fuel Acquired, 100% to One Company, MMBTU’s Burned (Coal)
Generation Administration	MW Generating Capability, Level of Construction-Production, 100% to One Company
Generation Business Services	MW Generating Capability, Level of Construction-Production, 100% to One Company
Generation Engineering and Technical Services - Engineering Project Field Services	100% to One Company, MW Generating Capability, Level of Construction-Production
Information Technology	100% to One Company, Total Assets, Peak Load, Number of Electric Retail Customers, Number of Employees
Legal GC/Administration	Total Assets, 100% to One Company, Total Fixed Assets
Real Estate & Workplace Services	100% to One Company, Number of Trans Pole Miles, Total Assets
Regulatory Services	Total Assets, Total Fixed Assets, Number of Trans Pole Miles, 100% to One Company
Risk and Strategic Initiatives	Total Fixed Assets, Total Assets, AEPSC Past 3 Months Total Bill, 100% to One Company
Security, Aviation & Procurement	Number of Employees, 100% to One Company
Shared Services	Past 3 Months Total Bill, Total Assets, Total Fixed Assets
Supply Chain & Fleet Operations	100% to One Company. Total Assets, Number of Purchase Orders
Transmission Administration	Total Assets, Level of Construction-Transmission, Number of Transmission Pole Miles
Transmission Engineering and Project Services	100% to One Company, Level of Construction-Transmission, Total Assets
Transmission Projects	AEPSC Past 3 Months Bill
Transmission Region	Level of Construction-Transmission,

GROUP/FUNCTION	***PRIMARY ALLOCATION FACTORS***
Operations	Number of Transmission Pole Miles, 100% to One Company
Transmission Reliability Compliance	Number of Transmission Pole Miles, Total Assets, 100% to One Company
Transmission Strategy, Planning, & Business Development	Level of Construction-Transmission, Number of Transmission Pole Miles, 100% to One Company
Transmission Trans Co and Joint Venture Projects	AEPSC Past 3 Months Bill
Transource Energy	100% to One Company, Level of Construction – Transmission, Number of Trans Pole Miles
Treasury	Total Assets, AEPSC Past 3 Months Total Bill, 100% to One Company

SUMMARY

The following table is a listing of the affiliate contracts with each electric utility in the AEP System.

COMPANY NAME	***DATE***	***CONTRACT***
AEP Texas Central Company (Formerly Central Power and Light)	04/26/85	Oklaunion Unit No. 1 Construction ownership and Operating Agreement
	07/01/93	Rail Car Lease Agreement(West)
	08/03/95	East HVDC Interconnection Facilities Use and Maintenance Agreement
	06/01/96	General Pole Attachment Agreement between CP&L and C3 Communications (formerly CSW Communications, Inc.)
	01/01/97	CSW Operating Agreement
	07/29/97	Rail Car Maintenance Facility Agreement (West)
	11/17/97	Amended and restated South Texas Project participation agreement between City of San Antonio, CP&L, Houston Lighting and Power Co., City of Austin & STP Nuclear Operating Company (as Operator)
	03/26/99	Electric Service Contract between Frontera General Limited Partners and Central Power and Light.
	03/30/99	Interconnection Agreement Between CP&L and Frontera Generation Limited
	06/01/99	CSW System General Agreement
	07/08/99	Memorandum of Understanding (West) Between C3 Communications Inc and Public Service Company of Oklahoma, Southwestern Electric Power Company, Central Power and Light, and West Texas Utilities
	10/29/99	Transmission Coordination Agreement (West)
	06/15/00	AEP Co. Inc. and its Consolidated Affiliated Tax Agreement regarding methods of allocated Consolidated Income Tax
	06/15/00	AEPSC Service Agreement with Central Power and Light
	06/16/00	Amended and Restated Purchase Agreement Between CSW Credit, Inc. and Affiliate (West) Companies

COMPANY NAME	DATE	CONTRACT
	12/18/02	AEP System Utility Money Pool Agreement
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	AEP System Tax Agreement
	12/01/09	AEP System Transmission Center Agreement
AEP Texas North Company (Formerly West Texas Utilities)	04/26/85	Oklaunion Union No 1 Construction, Ownership and Operating Agreement
	09/14/88	Oklaunion HVDC Project Construction, Ownership and Operating Agreement
	07/01/93	Rail Car Lease Agreement(West)
	07/01/96	Pole Attachment License Agreement (West) between West Texas and C3 Communications (Formerly CSW Communications)
	01/01/97	CSW Operating Agreement
	06/04/97	Abilene/San Angelo Fiber System Agreement between C3 Communications (Formerly CSW Communications) and West Texas Utilities Company
	12/22/97	Energy Conservation Measure Utility/Energy Service Company Agency Agreement
	06/01/99	CSW System General Agreement
	07/08/99	Memorandum of understanding (West)between C3 Communications, Inc. and Public Service of Oklahoma, Southwestern Electric, Central Power and Light and West Texas
	10/29/99	Transmission Coordination Agreement (West) Regulated Companies
	06/15/00	American Electric Power Company, Inc. and it’s Consolidated Affiliated Tax Agreement regarding methods of allocated consolidated Income Tax
	06/15/00	AEPSC Service Agreement with West Texas Utilities Company
	06/16/00	Amended and Restated Purchase Agreement between CSW Credit, Inc. and Affiliate (West) Companies
	06/26/01	Interconnection Agreement (ERCOT Generation) between AEPTN & PSO
	10/30/01	Construction Agreement/Trent Wind Farm LP
	12/18/02	AEP System Utility Money Pool Agreement

COMPANY NAME	DATE	CONTRACT
	11/16/04	Interconnection Agreement Between AEP Texas North and PSO
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	American Electric Power Company, Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of allocated consolidated Income Tax
	05/25/07	Power Purchase and Sale Agreement between AEP Texas North and AEP Energy Partners (fna CSW Power Marketing Inc.)
	12/01/09	AEP System Transmission Center Agreement
Appalachian Power Company	08/11/41	Land Purchase Contract between APCo and the Franklin Real Estate Company
	09/14/48	Coal Supply Agreement Between APCo and Central Appalachian Coal
	11/25/70	Purchase Agreement between APCO and Indiana Franklin Realty Inc.
	07/29/73	Appalachian Power & Ohio Power (Amos Plant)
	12/01/76	Indenture Between APCo and Cedar Coal
	03/01/78	Indenture Between APCo and Southern Appalachian Coal Company
	06/01/78	Racine Hydro Operating Agreement
	01/01/79	Central Machine Shop Agreement
	09/15/80	Putnam Coal Transfer Agreement between APCo and OPCo
	10/03/83	Agreement Between Appalachian Power Company and AEP Pro Service (Formerly AEP Energy Services
	04/01/84	Transmission Agreement
	05/01/86	Barge Transportation Agreement and Appendix A
	04/27/87	Interconnection Agreement
	07/30/87	Mutual Assistance Agreement
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	12/31/96	Affiliated Transactions Agreement (East Companies)
	03/06/97	Agreement Between Appalachian Power Company and AEP Energy Services Inc.
	01/01/98	Master Site Agreement (East) with AEP Operating Companies and AEP Communications

COMPANY NAME	DATE	CONTRACT
		LLC
	01/01/98	Appalachian Power Company and Ohio Power Company (Sporn Plant)
	02/12/98	Fiber Optic Agreement (East) with AEP Communications
	03/01/98	Pole Attachment License Agreement (EAST) between AEP Operating Companies and AEP Communications LLC
	03/04/98	Agreement between AEP Communications LLC and Appalachian Power Company
	06/15/00	AEPSC Service Agreement with Appalachian Power Company
	06/15/00	American Electric Power and it’s consolidated Affiliated Tax Agreements regarding methods of allocating consolidated income taxes
	06/16/00	Purchase Agreement Between CSW Credit and it’s affiliate client companies
	12/18/02	AEP System Utility Money Pool Agreement
	05/04/04	Arrangement for the use of the Amos Simulator
	08/25/04	Third Amended and Restated Purchase Agreement between AEP Credit and Appalachian Power Company
	08/25/04	Third Amended and Restated Agency Agreement between AEP Credit and Appalachian Power
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	AEP Co, Inc. and its Consolidated Affiliate Tax agreement regarding methods of Allocating Consolidated Income Taxes.
	03/22/06	Amendment No. 1 to the Third Amended and Restated Purchase Agreement between AEP Credit and Appalachian Power
	03/22/06	Amendment No. 1 to the Third Amended and Restated Agency Agreement between AEP Credit and Appalachian Power
	07/01/06	Amendment No. 1 and Consent to AEP System Rail Car Use Agreement
	11/16/07	Gypsum And Purge Stream Waste Disposal Agreement
	01/30/08	Amendment No. 2 to the Third Amended and Restated Purchase Agreement between AEP

COMPANY NAME	***DATE***	***CONTRACT***
		Credit and Appalachian Power
	01/30/08	Amendment No. 2 to the Third Amended and Restated Agency Agreement between AEP Credit and Appalachian Power
	05/15/08	Agreement Between Appalachian Power Company and AEPSC
	02/12/12	Executed Notice of Intent by Ohio Power Company to Terminate Sporn Plant Operating Agreement
	10/18/12	AEPSC and APCO Service Agreement
	12/27/12	APCO and AEP West Virginia Transmission Service Agreement
	08/01/13	Termination of Coal Transfer Agreement for Putman
	08/01/13	Railcar Maintenance Agreement
	09/12/13	Amendment No. 1 to Barge Transportation Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use Agreement
	12/16/13	Amended and Restated Urea Handling Agreement
	12/16/13	Amended and Restated Cook Coal Terminal Transfer Agreement
	12/31/13	Assignment of Gysum and Purge Stream Waste Disposal Agreement
	12/31/13	Termination of Racine Hydro Project Operating
	01/01/14	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts
	01/01/14	Affiliated Transactions Agreement for Sharing Materials and Supplies
	01/01/14	Sporn Plant Operating Agreement
	01/01/14	Simulator Lease Agreement
	01/01/14	Assignment of Central Machine Shop Agreement date January 1, 1979
	01/01/14	Bridge Agreement
	01/01/14	Power Coordination Agreement
Columbus Southern Power Company	12/31/11	Columbus Southern Power Company was merged into Ohio Power Company December 31, 2011. All contracts unique to Columbus Southern Power have been moved to Ohio Power Company.
Indiana	04/30/48	Purchase Contract between Indiana Franklin

COMPANY NAME	DATE	CONTRACT
Michigan Power Company		Realty, Inc.
	04/04/50	Purchase Contract between The Franklin Real Estate Company.
	01/01/79	Central Machine Shop Agreement/Appalachian Power
	01/01/82	Coal Supply Agreement/Blackhawk Coal
	04/01/82	AEP System Rail Car Use Agreement
	04/08/83	Agreement Between Indiana Michigan Power and AEP ProServ
	06/17/83	Cook Coal Terminal Coal Transfer Agreement
	04/01/84	Transmission Agreement
	10/21/85	Amendment to Coal Supply Agreement/Blackhawk Coal
	05/01/86	Barge Transportation Agreement and Appendix A
	04/27/87	Interconnection Agreement
	07/30/87	Mutual Assistance Agreement
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	09/27/96	Agreement Between Indiana Michigan Power and AEP Energy Services, Inc.(Formerly AEP Energy Solutions
	12/31/96	Affiliated Transactions Agreement (East Companies)
	01/01/98	Master Site Agreement(East) with AEP Operating Companies and AEP Communications LLC
	02/12/98	Fiber Optic Agreement/AEP Communications
	03/01/98	Pole Attachment License Agreement (East)
	03/04/98	Agreement Between Indiana Michigan Power and AEP Communications
	10/14/98	Agreement Between Indiana Michigan Power and AEP Communications, Inc.
	06/15/00	AEPSC Service Agreement with Indiana Michigan
	06/15/00	Power Company
		American Electric Power Company, Inc. and
	06/15/00	it’s Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
		Purchase Agreement Between CSW Credit and
	06/16/00	it’s Affiliate Client Companies
		AEP System Utility Money Pool Agreement
	12/18/02	Agency Agreement Between CSW Credit and

COMPANY NAME	DATE	CONTRACT
	04/21/04	Indiana Michigan Power Company
		Unit Power Agreement Amendment No 1 between
	05/04/04	I&M and AEP
		Arrangement for the use of the Amos Simulator
	05/04/04	Fiber Optic Agreement Between AEP
	05/04/04	Communications, LLC and I&M
		Unit 2 Operating Agreement between I&M and
	05/04/04	AEG
		Third Amended and Restated Purchase Agreement
	08/25/04	Third Amended and Restated Agency Agreement
	08/25/04	AEP System Amended and Restated Utility Money
	12/09/04	Pool Agreement
		AEP Co. Inc. and it's Consolidated Affiliated
	01/01/05	Tax Agreement regarding methods of Allocating
		Consolidated Income Taxes
		Amendment No 1 and Consent to AEP System Rail
	07/01/06	Car Agreement
		Indiana Michigan Power Company & AEP
	05/16/07	Generating Company Operation and Maintenance
		Agreement
		Transmission Service Agreement between
	02/15/11	Indiana Michigan Power Company and AEP
		Indiana Michigan Transmission Company
		Joint License Agreement between Indiana
	02/15/11	Michigan Power Company and AEP Indiana
		Michigan Transmission Company
		Rail Car Maintenance Agreement
	08/01/13	Amendment No. 1 to Barge Transportation
	09/12/13	Agreement
		Amendment No. 2 to AEP System Rail Car Use
	09/12/13	Amended and Restated Urea Handling Agreement
	12/16/13	Amended and Restated Cook Coal Terminal
	12/16/13	Transfer Agreement
		Affiliated Transactions Agreement for Sharing
	01/01/14	Capitalized Spare Parts
		Affiliated Transactions Agreement for Sharing
	01/01/14	Materials and Supplies
		Urea Handling Agreement (AEP Generation
	01/01/14	Resources)
		Crew Agreement – Vessels
	01/01/14	Bridge Agreement

COMPANY NAME	***DATE***	***CONTRACT***
	01/01/14 01/01/14	Power Coordination Agreement
Kentucky Power Company	06/07/63	Purchase Contract between KPCO and The Franklin Real Estate Company
	03/31/75	Purchase Contract between KPCO and Indiana Franklin Realty, Inc.
	01/01/79	Central Machine Shop Agreement/Appalachian Power
	07/07/83	Agreement Between Kentucky Power and ProServ
	04/01/84	Transmission Agreement
	04/27/87	Interconnection Agreements
	07/30/87	Mutual Assistance Agreement
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	09/27/96	Agreement between Kentucky Power and AEP Energy Services, Inc.
	12/31/96	Affiliated Transactions Agreement (East Companies)
	11/18/97	Agreement between Kentucky Power and AEP Communications, LLC
	01/01/98	Master Site Agreements (East) With AEP Operating Companies
	02/12/98	Fiber Optic Agreement (East) with AEP Communications
	03/01/98	Pole Attachment License Agreement/AEP Communications LLC
	03/04/98	AEP Communications, LLC with Affiliate Companies
	06/15/00	AEP Co. Inc. and it’s Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	06/15/00	AEPSC Service Agreement with Kentucky Power
	06/16/00	Purchase Agreement between AEP Credit and it’s Affiliate Client Companies
	12/18/02	AEP System Utility Money Pool Agreement
	05/04/04	Arrangement for the Use of the Amos Simulator
	08/25/04	Third Amended and Restated Purchase Agreement Between AEP Credit and Kentucky Power
	08/25/04	Third Amended and Restated Agency Agreement Between AEP Credit and Kentucky Power
	12/09/04	AEP System Amended and Restated Money Pool

COMPANY NAME	***DATE***	***CONTRACT***
		Agreement
	01/01/05	American Electric Power Company, Inc. and it’s Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	08/01/13	Railcar Maintenance Agreement
	09/12/13	Amendment No. 1 to Barge Transportation Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use
	12/16/13	Amended and Restated Urea Handling Agreement
	12/16/13	Amended and Restated Cook Coal Terminal Transfer Agreement
	12/31/13	Gyspum Letter Agreement
	12/31/13	Assignment of Gypsum and Purge Stream Waste Disposal Agreement
	01/01/14	Affiliated Transactions Agreement for Sharing Capitalized Spare Parts
	01/01/14	Affiliated Transactions Agreement for Sharing Materials and Supplies
	01/01/14	Mitchell Plant Operating Agreement
	01/01/14	Kammer Plant Operating Agreement
	01/01/14	Mitchell Coal Pile Run-Off Agreement
	01/01/14	Bridge Agreement
	01/01/14	Power Coordination Agreement
Kingsport Power Company	01/01/72	Purchase Contract Between KGPCO and Indiana Franklin Realty, Inc.
	01/01/79	Central Machine Shop Agreement/Appalachian Power
	07/07/83	Agreement Between Kingsport Power Company and AEP ProServ
	07/30/87	Mutual Assistance Agreement
	09/27/96	Agreement Between Kingsport Power Company and AEP Energy Services
	12/31/96	Affiliate Transactions Agreement (East Companies)
	01/01/98	Master Site Agreement (East) with AEP Operating Companies
	06/15/00	AEP Co, Inc and it’s Consolidated Affiliate Tax Agreement regarding methods of Allocating Consolidated Income Tax
	06/15/00	AEPSC Service Agreement with Kingsport Power

COMPANY NAME	***DATE***	***CONTRACT***
	06/16/00	Purchase Agreement Between CSW Credit and Affiliate Client Companies
	12/18/02	AEP System Utility Money Pool Agreement
	08/25/04	Third Amended and Restated Purchase Agreement Between AEP Credit and Kingsport Power
	08/25/04	Third Amended and Restated Agency Agreement Between AEP Credit and Kingsport Power
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	American Electric Power Company, Inc. and it's Consolidated Affiliate Tax Agreement regarding methods of Allocating Consolidated Income Taxes
Ohio Power Company	08/11/41	Land Purchase Contract/Franklin Real Estate Company
	11/25/70	Purchase Contract/Indiana Franklin Realty, Inc.
	10/01/72	Indenture Agreement Between Ohio Power Company and Southern Ohio Coal
	07/29/73	Appalachian Power & Ohio Power (Amos Plant)
	02/01/74	Supplemental Indenture OPCO, Ohio Electric, Southern Ohio Coal Company- Relating to delivery of coal from Meigs
	06/01/78	Racine Hydro Operating Agreement
	01/01/79	Central Machine Shop Agreement
	09/15/80	Putnam Coal Transfer Agreement Between APCo and OPCo
	04/01/82	AEP System Rail Car Use Agreement
	04/01/83	Amended and Restated Coal Supply Agreement between Ohio Power and Central Ohio Coal
	04/08/83	Agreement between Ohio Power Company and AEP Pro Serv, Inc
	06/17/83	Cook Coal Terminal Coal Transfer Agreement
	04/01/84	Transmission Agreement
	05/01/86	Barge Transportation Agreement and Appendix A
	04/27/87	Interconnection Agreement
	07/30/87	Mutual Assistance Agreement
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	09/27/96	Agreement between Ohio Power Company and AEP Energy Services

COMPANY NAME	***DATE***	***CONTRACT***
	12/31/96	Affiliated Transactions Agreement (East Companies)
	01/01/98	Master Site Agreement (East) with AEP Operating Companies
	01/01/98	Appalachian Power Company and Ohio Power Company (Sporn Plant)
	02/12/98	Agreement Between Columbus Southern Power (Which was merged into Ohio Power Company effective December 31, 2011), Ohio Power and AEP Communications
	02/12/98	Fiber Optic Agreement/AEP Communications
	03/01/98	Pole Attachment License Agreement/AEP Communications LLC
	03/04/98	AEP Communications, LLC with Affiliated Companies
	03/15/99	Service Agreement between Ohio Power, AEPSC and Cardinal Operating Co.
	05/31/00	Ohio Power and AEPES – Buckeye Power Supply Management Agreement
	06/15/00	American Electric Power Company, Inc. and its
	06/15/00	Consolidated Affiliate Tax Agreement regarding Methods of Allocating Consolidated Income Taxes
	06/16/00	AEPSC Service Agreement with Ohio Power Purchase Agreement Between AEP Credit Inc. and Affiliate Client Companies
	12/18/02	AEP System Utility Money Pool Agreement
	05/04/04	Arrangement for the Use of the Amos Simulator
	08/25/04	Third Amended and Restated Purchase Agreement
	08/25/04	Third Amended and Restated Agency Agreement
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	AEP Co, Inc and It's Consolidated Affiliate Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	07/01/06	Amendment No 1 and Consent to AEP System Rail Car Use Agreement
	09/01/07	Gypsum Agreement
	11/16/07	Gypsum and Purge Stream Waste Disposal Agreement
	12/01/09	Transmission Center Agreement

COMPANY NAME	***DATE***	***CONTRACT***
	01/01/11	AEP System Transmission Center Agreement Transmission Service Agreement between Ohio Power Company and AEP Ohio Transmission Company
	01/01/11	Joint License Agreement between Ohio Power Company and AEP Ohio Transmission Company
	02/12/12	Executed Notice of Intent by Ohio Power Company to Terminate Sporn Plant Operating Agreement
	08/01/13	Termination of Coal Transfer Agreement for Putman
	08/01/13	Rail Car Maintenance Agreement
	09/12/13	Amendment No. 1 to Barge Transportation Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use
	12/16/13	Amended and Restated Cook Coal Terminal Transfer Agreement
	12/31/13	Termination of Racine Hydro Project Operating Agreement
	12/31/13	Assignment, Assumption and Consent Agreement of Rail Car Assets
	12/31/13	Cardinal Owners’ Internal Side Letter and Assignment
	12/31/13	Assignment of Gypsum and Purge Stream Waste Disposal Agreement
	12/31/14	Assignment of Lawrenceburg Purchase Power Agreement
	01/01/14	Affiliated Transactions Agreement for Sharing Materials and Supplies
	01/01/14	Assignment of Central Machine Shop Agreement dated January 1, 1979
	01/01/14	Bridge Agreement
	01/01/14	Power Supply Agreement
	01/01/14	Telecommunications Services Agreement
Public Service Company of Oklahoma	04/26/85	Oklaunion Unit No. 1 Construction, Ownership and Operating Agreement
	09/14/88	Oklaunion HVDC Project Construction, Ownership and Operating Agreement
	07/01/93	Rail Car Lease Agreement(West)
	08/03/95	East HVDC Interconnection Agreement/West Regulated Companies

COMPANY NAME	***DATE***	***CONTRACT***
	01/01/97	CSW Operating Agreement
	07/29/97	Rail Car Maintenance Facility Agreement
	06/01/99	CSW System General Agreement
	07/08/99	Memorandum of Understanding (West) Between C3 Communications, Inc., Public Service Company of Oklahoma, Southwestern Electric Power Company, Central Power and Light, and West Texas Utilities.
	10/29/99	Transmission Coordination Agreement(West)
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliate Tax Agreements
	06/15/00	AEPSC Service Agreement with Public Service Company of Oklahoma
	06/16/00	Amended and Restated Agency Agreement Between CSW Credit and it's Affiliates
	06/16/00	Amended and Restated Purchase Agreement Between CSW Credit and it's Affiliates
	07/16/01	Master Site Agreement Between Public Service Company of Oklahoma and C3 Communications
	07/16/01	Fiber Optic Agreement Between C3 Communication and Public Service Company
	07/16/01	Agreement between C3 Communications and Public Service Company of Oklahoma
	12/21/01	Operating Agreement-PSO, SWEPCO, AEPSC
	12/18/02	AEP System Utility Money Pool Agreement
	07/25/03	Second Amended and Restated Agency Agreement between AEP Credit and Public Service Company of Oklahoma
	07/25/03	Second Amended and Restated Purchase Agreement between AEP Credit and Public Service Company of Oklahoma
	08/25/04	Third Amended and Restated Purchase Agreement
	08/25/04	Third Amended and Restated Agency Agreement
	11/16/04	Interconnection Agreement (ERCOT Generation) between AEPTN & PSO.
	12/09/04	AEP System Amended and Restated Money Pool Agreement
	01/01/05	American Electric Power Company, and it's Consolidated Tax Affiliates
	02/10/05	Operating Agreement PSO, SWEPCO and AEPSC
	07/01/06	Amendment No 1 and consent to AEP System Rail

COMPANY NAME	DATE	CONTRACT
		Car Use Agreement
	12/01/09	AEP System Transmission Center Agreement
	01/01/10	Transmission Service Agreement between Public Service Company of Oklahoma and AEP Oklahoma Transmission Company
	01/01/10	Joint License Agreement between Public Service Company of Oklahoma and AEP Oklahoma Transmission Company
	08/01/13	Rail Car Maintenance Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use Agreement
Southwestern Electric Power Company	07/01/93	Rail Car Lease Agreement (West)
	08/03/95	East HVDC Interconnection Use and Maintenance Agreement
	01/01/97	CSW Operating Agreement
	07/29/97	Rail Car Maintenance Facility Agreement (West)
	06/01/99	CSW System General Agreement
	07/08/99	Memorandum of Understanding (West) Between C3 Communications, Public Service Company,
	10/29/99	Transmission Coordination Agreement (West)
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliates Tax Agreements
	06/15/00	AEPSC Service Agreement with Southwest Power Electric
	06/16/00	Amended and Restated Purchase Agreement Between CSW and Affiliate (West) Companies
	05/31/01	Lignite Mining Agreement
	07/16/01	Master Site Agreement Between Southwestern Electric Company and C3 Communications
	07/16/01	Fiber Optic Agreement Between C3 Communications, Inc. and Southwestern Electric Power Company
	07/16/01	Agreement Between C3 Communications, Inc. and Southwestern Electric Power Company
	12/21/01	Operating Agreement PSO, SWEPCo, AEPSC
	08/06/02	Interconnection Agreement Between SWEPCo and Eastex Cogeneration LP
	12/18/02	AEP System Utility Money Pool Agreement
	07/25/03	Second Amended and Restated Agency Agreement Between AEP Credit and SWEPCo

COMPANY NAME	***DATE***	***CONTRACT***
	07/25/03	Second Amended and Restated Purchase Agreement Between AEP Credit and SWEPCo
	08/25/04	Third Amended and Restated Purchase Agreement Between AEP Credit and Southwestern Electric Power
	08/25/04	Third Amended and Restated Agency Agreement Between AEP Credit and Southwestern Electric Power
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	American Electric Power Company, Inc. and Its Consolidated Affiliated Tax Agreements
	02/10/05	Operating Agreement PSO, SWEPCO, AEPSC
	07/01/06	Amendment No 1 and Consent to AEP System Rail Car Use
	12/01/09	AEP System Transmission Center Agreement
	12/29/09	Amended and Restated Lignite Mining Agreement
	05/06/11	Transmission Service Agreement between Southwestern Electric Power Company and AEP Southwestern Transmission Company
	05/06/11	Joint License Agreement between Southwestern Electric Power Company and AEP Southwestern Transmission Company
	08/01/13	Rail Car Maintenance Agreement
	09/12/13	Amendment No. 2 to AEP System Rail Car Use
	12/31/13	Assignment, Assumption and Consent Agreement of Rail Car Assets
Wheeling Power Company	08/11/41	Land Purchase Contract/The Franklin Real Estate Company
	10/03/83	Agreement between Wheeling Power Company and AEP Pro Serve, Inc. (Formerly AEP Energy Services)
	07/30/87	Mutual Assistance Agreement
	12/31/96	Affiliated Transactions Agreement (East Companies)
	01/09/97	Agreement between Wheeling Power Company and AEP Energy Services, Inc.
	01/01/98	Master Site Agreement (East) with AEP Operating Companies and AEP Communications, LLC
	03/04/98	AEP Communications, LLC with Affiliate

COMPANY NAME	DATE	CONTRACT
		Companies
	02/12/98	Fiber Optic Agreement/AEP Communications
	03/01/98	Pole Attachment License Agreement/AEP Communications LLC
	06/15/00	AEPSC Service Agreement
	06/15/00	AEP System Tax Agreement
	12/18/02	AEP System Utility Money Pool Agreement
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/05	American Electric Power Company, and it's Consolidated Tax Affiliates
	05/15/08	Agreement between Wheeling Power Company and AEPSC
Electric Transmission Texas	12/21/07	Electric Transmission Texas Service Agreement
PATH West Virginia Transmission Company	09/01/07	PATH West Virginia Transmission Company Service Agreement
AEP Indiana Michigan Transmission Company	02/15/11	Transmission Company Services Agreement between AEP Indiana Michigan Transmission Company and Indiana Michigan Power Company
	02/15/11	Joint License Agreement between AEP Indiana Michigan Transmission Company and Indiana Michigan Power Company
	02/15/11	Service Agreement between AEP Indiana Michigan Transmission Company and American Electric Power Service Corporation
AEP Ohio Transmission Company	01/01/11	Transmission Company Services Agreement between AEP Ohio Transmission Company and Ohio Power Company
	01/01/11	Transmission Company Services Agreement between AEP Ohio Transmission Company and Columbus Southern Power Company
	01/01/11	Joint License Agreement between AEP Ohio Transmission Company and Ohio Power Company
	01/01/11	Joint License Agreement between AEP Ohio Transmission Company and Columbus Southern Power Company

COMPANY NAME	***DATE***	***CONTRACT***
	01/01/11	Service Agreement between AEP Ohio Transmission Company and American Electric Power Service Corporation
AEP Oklahoma Transmission Company	01/01/10	Transmission Company Services Agreement between AEP Oklahoma Transmission Company and Public Service Company of Oklahoma
	01/01/10	Joint License Agreement between AEP Oklahoma Transmission Company and Public Service Company of Oklahoma
	10/27/10	Service Agreement between AEP Oklahoma Transmission Company and American Electric Power Service Corporation
AEP Southwestern Transmission Company	05/06/11	Transmission Company Services Agreement between AEP Southwestern Transmission Company and Southwestern Electric Power Company
	05/06/11	Joint License Agreement between AEP Southwestern Transmission Company and Southwestern Electric Power Company
	05/06/11	Service Agreement between AEP Southwestern Transmission Company and American Electric Power Service Corporation

Filing Requirement
807 KAR 5:001 Section 4(1)

Filing Requirement:

All communications shall be addressed to: Public Service Commission, 211 Sower Boulevard, Post Office Box 615, Frankfort, Kentucky 40602.

Response:

Kentucky Power Company will comply with requirements established in 807 KAR 5:001 Section 4(1).

Filing Requirement
807 KAR 5:001 Section 4(2)

Filing Requirement:

Each case shall receive a number and a style descriptive of the subject matter. The number and style shall be placed on each subsequent paper filed in the case.

Response:

Kentucky Power Company will comply with the requirement established in 807 KAR 5:001 Section 4(2).

Filing Requirement
807 KAR 5:001 Section 4(3)

Filing Requirement:

Signing Papers

(a) ***A paper shall be signed by the submitting party or attorney and shall include the name, address, telephone number, facsimile number, and electronic mail address, if any, of the attorney of record or submitting party.***

(b) ***A paper shall be verified or under oath if required by statute, administrative regulation, or order of the commission.***

Response:

Kentucky Power Company will comply with the requirements established in 807 KAR 5:001 Section 4(3).

Filing Requirement
807 KAR 5:001 Section 4(4)

Filing Requirement:

A person shall not file a paper on behalf of another person, or otherwise represent another person, unless the person is an attorney licensed to practice law in Kentucky or an attorney who has complied with SCR 3.030(2). An attorney who is not licensed to practice law in Kentucky shall present evidence of his or her compliance with SCR 3.030(2) if appearing before the commission.

Response:

Kentucky Power Company will comply with the requirement established in 807 KAR 5:001 Section 4(4).

Filing Requirement
807 KAR 5:001 Section 4(9)

Filing Requirement:

Filing.

(a) Unless electronic filing procedures established in Section 8 of this administrative regulation are used, a paper shall not be deemed filed with the commission until the paper:

1. ***Is physically received by the executive director at the commission's offices during the commission's official business hours; and***

2. ***Meets all applicable requirements of KRS Chapter 278 and KAR Title 807.***

(b) The executive director shall endorse upon each paper or document accepted for filing the date of its filing. The endorsement shall constitute the filing of the paper or document.

Response:

Kentucky Power Company is filing its application for an Adjustment in Electric Rates in electronic format.

Filing Requirement
807 KAR 5:001 Section 4(10)

Filing Requirement:

Privacy protection for filings.

(a) If a person files a paper containing personal information, the person shall encrypt or redact the paper so that personal information cannot be read. Personal information shall include a business name; an individual's first name or first initial and last name; personal mark; or unique biometric or genetic print or image, in combination with one (1) or more of the following data elements:

1. The digits of a Social Security number or taxpayer identification number;
2. The month and date of an individual's birth;
3. The digits of an account number, credit card number, or debit card number that, in combination with any required security code, access code, or password, would permit access to an account;
4. A driver's license number, state identification card number, or other individual identification number issued by any agency;
5. A passport number or other identification number issued by the United States government;
6. "Individually identifiable health information" as defined by 45 C.F.R. 160.103, except for education records covered by the Family Educational Rights and Privacy Act, as amended, 20 U.S.C. 1232g; or
7. The address, phone number, or email address of an individual who is not a party and has not requested to be a party.

(b) To redact the paper, the filing party shall replace the identifiers with neutral placeholders or cover the identifiers with an indelible mark that so obscures the identifiers that the identifiers cannot be read.

(c) The responsibility to review for compliance with this section and redact a paper shall rest with the party that files the paper.

Response:

Kentucky Power Company will comply with the requirement established in 807 KAR 5:001 Section 4(10).

Filing Requirement
807 KAR 5:001 Section 7(1)

Filing Requirement:

Unless the commission orders otherwise or the electronic filing procedures established in Section 8 of this administrative regulation are used, if a paper is filed with the commission, an original unbound and ten (10) additional copies in paper medium shall be filed.

Response:

Kentucky Power Company is filing its application for an Adjustment in Electric Rates in electronic format.

Filing Requirement
807 KAR 5:001 Section 7(2)

Filing Requirement:

Each paper filed with the commission shall conform to the requirements established in this subsection.

(a) Form. Each filing shall be printed or typewritten, double spaced, and on one (1) side of the page only.

(b) Size. Each filing shall be on eight and one-half (8 1/2) inches by eleven (11) inches paper.

(c) Font. Each filing shall be in type no smaller than twelve (12) points, except footnotes, which may be in type no smaller than ten (10) points.

Response:

Kentucky Power Company will comply with requirements established in 807 KAR 5:001 Section 7(2).

Filing Requirement
807 KAR 5:001 Section 7(3)

Filing Requirement:

Except as provided for in Section 8 of this administrative regulation, a filing made with the commission outside its business hours shall be considered as filed on the commission's next business day.

Response:

Kentucky Power Company is filing its application for an Adjustment in Electric Rates in electronic format.

Filing Requirement
807 KAR 5:001 Section 7(4)

Filing Requirement:

A paper submitted by facsimile transmission shall not be accepted.

Response:

Kentucky Power Company is filing its application for an Adjustment in Electric Rates in electronic format.

Filing Requirement
807 KAR 5:001 Section 8(1) et seq.

Filing Requirement:

Upon an applicant's timely election of the use of electronic filing procedures or upon order of the commission in a case that the commission has initiated on its own motion, the procedures established in this section shall be used in lieu of other filing procedures established in this administrative regulation.

Response:

Kentucky Power Company is filing its application for an Adjustment in Electric Rates in electronic format and will comply with all requirements.

Filing Requirement
807 KAR 5:001 Section 12 (1)

Filing Requirement:

If this administrative regulation requires that a financial exhibit be annexed to the application, the exhibit shall:

(a) For a utility that had $5,000,000 or more in gross annual revenue in the immediate past calendar year, cover operations for a twelve (12) month period, the period ending not more than ninety (90) days prior to the date the application is filed; or

(b) For a utility that had less than $5,000,000 in gross annual revenue in the immediate past calendar year, comply with paragraph (a) of this subsection or cover operations for the twelve (12) month period contained in the utility's most recent annual report on file with the commission, and contain a statement that:

1. ***Material changes have not occurred since the end of that twelve (12) month period; or***
2. ***Identifies all material changes that have occurred since the end of that twelve (12) month period.***

Response:

Please see Section IV.

Filing Requirement
807 KAR 5:001 Section 12 (2)(a)

Filing Requirement:

The exhibit shall disclose the following information in the order indicated:

(a) Amount and kinds of stock authorized;

Response:

Please see Section IV, page 1.

Filing Requirement
807 KAR 5:001 Section 12 (2)(b)

Filing Requirement:

Amount and kinds of stock issued and outstanding;

Response:

Please see Section IV, page 1.

Filing Requirement
807 KAR 5:001 Section 12 (2)(c)

Filing Requirement:

Terms of preference of preferred stock, cumulative or participating, or on dividends or assets or otherwise;

Response:

Please see Section IV, page 1.

Filing Requirement
807 KAR 5:001 Section 12 (2)(d)

Filing Requirement:

A brief description of each mortgage on property of applicant, giving date of execution, name of mortgagor, name of mortgagee or trustee, amount of indebtedness authorized to be secured, and the amount of indebtedness actually secured, together with sinking fund provisions, if applicable;

Response:

Please see Section IV, page 1.

Filing Requirement
807 KAR 5:001 Section 12 (2)(e)

Filing Requirement:

Amount of bonds authorized and amount issued, giving the name of the public utility that issued the same, describing each class separately and giving the date of issue, face value, rate of interest, date of maturity, and how secured, together with amount of interest paid during the last fiscal year;

Response:

Please see Section IV, page 1.

Filing Requirement
807 KAR 5:001 Section 12 (2)(f)

Filing Requirement:

Each note outstanding, giving date of issue, amount, date of maturity, rate of interest, in whose favor, together with amount of interest paid during the last fiscal year;

Response:

Please see Section IV, page 1.

Filing Requirement
807 KAR 5:001 Section 12 (2)(g)

Filing Requirement:

Other indebtedness, giving same by classes and describing security, if any, with a brief statement of the devolution or assumption of a portion of the indebtedness upon or by person or corporation if the original liability has been transferred, together with amount of interest paid during the last fiscal year;

Response:

Please see Section IV, page 2.

Filing Requirement
807 KAR 5:001 Section 12 (2)(h)

Filing Requirement:

Rate and amount of dividends paid during the five (5) previous fiscal years, and the amount of capital stock on which dividends were paid each year; and;

Response:

Please see Section IV, page 2.

Filing Requirement
807 KAR 5:001 Section 12 (2)(i)

Filing Requirement:

A detailed income statement and balance sheet.

Response:

Please see Section IV, pages 2-19.

Filing Requirement
807 KAR 5:001 Section 14 (1)

Filing Requirement:

Each application shall state the full name, mailing address, and electronic mail address of the applicant, and shall contain fully the facts on which the application is based, with a request for the order, authorization, permission, or certificate desired and a reference to the particular law requiring or providing for same.

Response:

The application is by petition and contains the full name, mailing address, and electronic mail address of the applicant:

Kentucky Power Company
PO Box 5190
Frankfort KY 40602
Kentucky_Regulatory_Services@aep.com

The application also contains fully the facts on which the application is based and otherwise fully complies with 807 KAR 5:001 Section 14(1).

Filing Requirement
807 KAR 5:001 Section 14 (2)

Filing Requirement:

If a corporation, the applicant shall identify in the application the state in which it is incorporated and the date of its incorporation, attest that it is currently in good standing in the state in which it is incorporated, and, if it is not a Kentucky corporation, state whether it is authorized to transact business in Kentucky.

Response:

Please see the attached Certificate of Existence dated December 11, 2014 as certified by the Commonwealth of Kentucky's Secretary of State.

Commonwealth of Kentucky
Alison Lundergan Grimes, Secretary of State

Alison Lundergan Grimes
Secretary of State
P. O. Box 718
Frankfort, KY 40602-0718
(502) 564-3490
http://www.sos.ky.gov

Certificate of Existence

Authentication number: 158397
Visit https://app.sos.ky.gov/ftshow/certvalidate.aspx to authenticate this certificate.

I, Alison Lundergan Grimes, Secretary of State of the Commonwealth of Kentucky, do hereby certify that according to the records in the Office of the Secretary of State,

KENTUCKY POWER COMPANY

is a corporation duly incorporated and existing under KRS Chapter 14A and KRS Chapter 271B, whose date of incorporation is July 21, 1919 and whose period of duration is perpetual.

I further certify that all fees and penalties owed to the Secretary of State have been paid; that Articles of Dissolution have not been filed; and that the most recent annual report required by KRS 14A.6-010 has been delivered to the Secretary of State.

IN WITNESS WHEREOF, I have hereunto set my hand and affixed my Official Seal at Frankfort, Kentucky, this 11th day of December, 2014, in the 223rd year of the Commonwealth.

COMMONWEALTH OF KENTUCKY
OFFICE OF SECRETARY OF STATE

Alison Lundergan Grimes
Secretary of State
Commonwealth of Kentucky
158397/0028317

Filing Requirement
807 KAR 5:001 Section 14 (3)

Filing Requirement:

If a limited liability company, the applicant shall identify in the application the state in which it is organized and the date on which it was organized, attest that it is in good standing in the state in which it is organized, and, if it is not a Kentucky limited liability company, state whether it is authorized to transact business in Kentucky.

Response:

Not applicable as Kentucky Power Company is not a limited liability company.

Filing Requirement
807 KAR 5:001 Section 14 (4)

Filing Requirement:

If the applicant is a limited partnership, a certified copy of its limited partnership agreement and all amendments, if any, shall be annexed to the application, or a written statement attesting that its partnership agreement and all amendments have been filed with the commission in a prior proceeding and referencing the case number of the prior proceeding.

Response:

Not applicable as Kentucky Power Company is not a limited partnership.

Filing Requirement
807 KAR 5:001 Section 16 (1)(a)

Filing Requirement:

Each application requesting a general adjustment in existing rates shall:

(a) Be supported by:

1. ***A twelve (12) month historical test period that may include adjustments for known and measurable changes; or***

2. ***A fully forecasted test period;***

Response:

Kentucky Power Company's Application for a general adjustment to its existing rates is supported by a twelve-month historical test year for the test period ended September 30, 2014 with adjustments for known and measurable changes.

Filing Requirement
807 KAR 5:001 Section 16 (1)(b)(1)

Filing Requirement:

A statement of the reason the adjustment is required.

Response:

Please see the Company's Application (Section I) and the testimonies of the Company's witnesses in Section III.

Filing Requirement
807 KAR 5:001 Section 16 (1)(b)(2)

Filing Requirement:

A certified copy of a certificate of assumed name as required by KRS 365.015 or a statement that a certificate is not necessary

Response:

The legal name of Kentucky Power Company is Kentucky Power Company; therefore, a certificate of assumed name is not necessary.

Filing Requirement
807 KAR 5:001 Section 16 (1)(b)(3)

Filing Requirement:

New or revised tariff sheets, if applicable in a format that complies with 807 KAR 5:011 with an effective date not less than thirty (30) days from the date the application is filed;

Response:

Please see Exhibit JAR-8 to the testimony of Company Witness Rogness in Section III to this Application.

Filing Requirement
807 KAR 5:001 Section 16 (1)(b)4

Filing Requirement:

New or revised tariff sheets, if applicable, identified in compliance with 807 KAR 5:011, shown either by providing:

a. ***The present and proposed tariffs in comparative form on the same sheet side by side or on facing sheets side by side; or***

b. ***A copy of the present tariff indicating proposed additions by italicized inserts or underscoring and striking over proposed deletions***;

Response:

Please see Exhibit JAR-9 to the testimony of Company Witness Rogness in Section III to this Application for a copy of the present tariff indicating proposed additions.

Filing Requirement
807 KAR 5:001 Section 16 (1)(b)(5)

Filing Requirement:

A statement that notice has been given in compliance with Section 17 of this administrative regulation with a copy of the notice; and

Response:

Customer notice has been given in compliance with 807 KAR 5:001 Section 17. Please see the following attachments for the Certification Of Compliance With Notice And Posting Requirements and a copy of the *Notice to the Customers of Kentucky Power Company*.

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)	Case No. 2014-00396

Certification Of Compliance With Notice And Posting Requirements

John A. Rogness III, Director Regulatory Services, Kentucky Power Company, a utility furnishing retail electric service within the Commonwealth of Kentucky, certifies the following:

1. On December 23, 2014, Kentucky Power Company filed an Application with the Public Service Commission of Kentucky for approval of an adjustment of its electric rates, terms and conditions of Kentucky Power Company, and seeking certain other relief.

2. In connection with its application Kentucky Power provided the following notice:

(a) Filed with the Public Service Commission on November 14, 2014 its Notice of Intent in accordance with the requirements of 807 KAR 5:001, Section 16(2) and KRS 278.183(2). A copy of the notice of intent also was provided on November 14, 2014 electronically and by United States mail to the Office of the Attorney General, Office of Rate Intervention in accordance with 807 KAR 5:001, Section 16(2)(c).

(b) The Customer Notice required by 807 KAR 5:001, Section 17(2) and 807 KAR 5:011, Section 8(2) will be published once a week for three consecutive weeks in a prominent manner in newspapers of general circulation in Kentucky Power's service area, with the first publication on or before the date of this application is filed with the Commission. The Customer Notice was first published beginning the week of December 15, 2014. An affidavit verifying the contents of the published notice, that the notice was published, and the dates of publication will be filed in accordance with 807 KAR 5:001, Section 17(3)(b) and 807 KAR 5:011, Section 8(3)(b) within 45 days of the date this Application is submitted to the Commission.

(c) On or before December 23, 2014 made the Public Posting required by 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011, Section 8(a), and provided a copy of the Application for public inspection at the Frankfort corporate office and Service Center buildings in the Company's service territory at the following locations:

(i) Frankfort Corporate Office, 101A Enterprise Dr., Frankfort, KY;

(ii) Ashland Service Center, 12333 Kevin Avenue, Ashland, KY;

(iii) Hazard Service Center, 1400 E. Main Street, Hazard, KY; and

(iv) Pikeville Service Center, 3249 N. Mayo Trail, Pikeville, KY.

The Public Posting and a copy of the Application will remain available for public inspection in conformity with the requirements of 807 KAR 5:001, Section 17(1)(c) and 807 KAR 5:011, Section 8(1)(c) until the Commission enters a final decision in this matter.

(d) On or before December 23, 2014 posted on its Web site (https://www.kentuckypower.com) the information and hyperlink required by 807 KAR 5:001, Section 17(1)(b) and 807 KAR 5:011, Section 8(1)(b). This information will remain available for public access and inspection in conformity with the requirements of 807 KAR 5:001, Section

17(1)(c) and 807 KAR 5:011, Section 8(1)(c) on Kentucky Power's website until the Commission enters a final decision in this matter.

3. The Customer Notice and Public Posting described in paragraphs 2(b) and 2(c) conformed to and contained the information required by 807 KAR 5:001, Section 17(4) and 807 KAR 5:011, Section 8(4).

4. The Customer Notice identified in paragraph 2 above and attached hereto contains a clear and concise explanation of the proposed change in the rate schedule applicable to each customer and thus pursuant to 807 KAR 5:001, Section 16(3) and 807 KAR 5:011, Section 8(5) is deemed a substitute for the notice required by 807 KAR 5:051, Section 2.

Given under my hand this 23rd day of December, 2014.

John A. Rogness, III
Director Regulatory Services
Kentucky Power Company
101A Enterprise Dr.
Frankfort, KY 40601

NOTICE

Please Take Notice that on or before December 23, 2014 Kentucky Power Company (Kentucky Power) will file with the Kentucky Public Service Commission (Commission) in Case No. 2014-00396 an application pursuant to Chapter 278 of the Kentucky Revised Statutes for authorization to adjust the rates it charges its customers for services rendered on and after January 23, 2015. If approved and not suspended, Kentucky Power will apply the new rates to all customer bills rendered on and after January 23, 2015 to recover costs of providing service to its customers on and after that date.

In addition to the rate changes described below, Kentucky Power proposes to add the Big Sandy Retirement Rider, Big Sandy 1 Operation Rider, PJM Rider, and the NERC Compliance and Cybersecurity Rider which will be applicable to the following tariffs: R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L. Kentucky Power is also proposing the Kentucky Economic Development Surcharge which will be applicable to the following tariffs: R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., and S.L.

Kentucky Power is proposing to combine the current Q.P. and C.I.P.-T.O.D. tariffs into a new Industrial General Service (I.G.S.) tariff. In addition, the following electric tariffs and/or charges are being eliminated: Emergency Curtailable Service-Capacity & Energy, Energy Price Curtailable Service Rider, and Experimental Real-Time Pricing. Kentucky Power has also made changes to the text of certain tariffs. Where the text changes to the tariffs are substantive in nature, the proposed language change is described below.

TARIFF CHANGES

TERMS AND CONDITIONS OF SERVICE

4. DEPOSITS.

Kentucky Power has modified its deposit requirements to: (a) give the Company the discretion to determine what type of guaranty is acceptable; (b) specify and modify the criteria for waiving a deposit; and (c) to specify and modify the criteria for when an additional or supplemental deposit may be required. The deposit requirements were further modified to define satisfactory payment criteria and satisfactory credit criteria.

12. BILLING FORM.

The Company has modified its Residential, Small Commercial, and Large Commercial and Industrial Bill Forms to include line items for the new Big Sandy Retirement Rider, Big Sandy 1 Operation Rider, PJM Rider, NERC Compliance and Cybersecurity Rider, and Kentucky Economic Development Surcharge.

14. MONITORING USAGE

The Company has modified the frequency of its customer usage monitoring from annually to quarterly.

17. DENIAL OR DISCONTINUANCE OF SERVICE.

The Company has modified the Denial or Discontinuation of Service provision so that the definition of a customer conforms with Commission regulations.

19. SPECIAL CHARGES.

In addition to modifying the rates for special charges to more closely match current costs to perform those services, the Company has modified the Special Charges section to clarify that no "Call-Outs" for re-connections following a discontinuation of service will take place after 10:00 PM and to add a charge for a customar-requested meter reading check.

A. Reconnection and Disconnect Charges

In cases where the Company has discontinued service as herein provided for, the Company reserves the right to assess a reconnection charge pursuant to 807 KAR 5:006, Section 9 (3) (b), payable in advanca, in accordance with the following schedule. However, those Custom ers qualifying for Winter Hardship Reconnection under 807 KAR 5:006 Section 16 shall be exempt from the reconnect charges.

1. Reconnect for nonpayment during regular hours	$ ~~12.94~~ *$21.00*
2. Reconnect at the end of the day (No "Call Out" required)	$ ~~17.26~~ *$30.00*
3. Reconnect for nonpayment whan a "Call Out" is required *prior to 10:00 PM* (A "Call Out" is when an employea must be called in to work on an overtime basis to make the reconnect trip. *Reconnections for nonpayment will not be made when e "Call Out" after 10:00 p.m. is required.)*	$ ~~35.95~~ *$95.00*
4. Reconnect for nonpayment when double time is required (Sunday and Holiday)	$ ~~44.58~~ *$124.00*
5. Termination or field trip	$ ~~8.63~~ *$13.00*

The reconnection charge for all Customers where service has been disconnected for fraudulent use of electricity will be the actual cost of the reconnection.

B. *Meter Reading Check*

Pursuant to 807 KAR 5:006, Section 9 (3) (d) in cases where a customer requests a meter be reread, and the second reading shows the original reading was correct, the Customer will be charged a fee of $21.00 to cover the handling cost.

C. *Returned Check Charge*

In cases where a customer pays by check, which is later returned as unpaid by the bank for any reason, the Customer will be charged a fee of ~~$7.00~~ *$18.00* to cover the handling costs.

D. *Meter Test Charge*

Where test of a meter is made upon written request of the Customer pursuant to 807 KAR 5:006, Section 19, the Customer will be charged ~~$14.38~~ *$48.00* if such test shows that the meter was not more than two percent (2%) fast.

TARIFF R.S.
(Residential Service)

RATE. (Tariff Codes 015, 017, 022)

Service Charge	$ ~~8.00~~ *$16.00* per month
Energy Charge:	~~8.590¢~~ *9.035¢* per KWH

VOLUNTEER FIRE DEPARTMENTS *(Tariff Code 024)*

The Company has clarified that this tariff is available to Volunteer Fire Departments subject to certain reporting requirements in accordance to KRS 278.172.

LOAD MANAGEMENT WATER-HEATING PROVISION. (Tariff Code 011)

For residential customers who install a ~~Company approved~~ load management water-heating system which consumes electrical energy ~~primarily~~ during off-peak hours specified by the Company and stores hot water for use during on-peak hours, of minimum capacity of 80 gallons, the last 250 KWH of use in any month shall be billed at ~~4.940¢~~ *5.216¢* per KWH.

SPECIAL TERMS AND CONDITIONS

The Company has clarified that in accordance with the Commission's regulations it will make an extension of up to 150 feet to a mobile home without charge.

The Company added the following paragraph:

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

TARIFF R.S. – L.M. – T.O.D.
(Residential Service Load Management Time-of-Day)

AVAILABILITY OF SERVICE.

The Company modified this provision to eliminate the requirement that the multiple-register meter be single phase to receive service under this tariff.

RATE. (Tariff Codes 028, 030, 032, 034)

Service Charge	$ ~~10.55~~ *18.70* per month
Energy Charge:	
All KWH used during on-peak billing period	~~13.227¢~~ *13.879¢* per KWH
All KWH used during off-peak billing period	~~4.940~~ *5.216¢* per KWH

SEPARATE METERING PROVISION.

Customers who use electric thermal storage space heating and water heaters which consume energy only during off-peak hours specified by the Company, or other automatically controlled load management devices such as space and/or water heating equipment that use energy only during off-peak hours specified by the Company, shall have the option of having these approved load management devices separately metered. The service charge for the separate meter shall be ~~$3.00~~ *$3.85* per month.

SPECIAL TERMS AND CONDITIONS

The Company added the following paragraph:

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

TARIFF R.S. – T.O.D.
(Residential Service Time-of-Day)

AVAILABILITY OF SERVICE.

The Company modified this provision to eliminate the requirement that the multiple-register meter be single phase to receive service under this tariff.

RATE. (Tariff Code 036)

Service Charge	$ ~~10.55~~ *$18.70* per month
Energy Charge:	
All KWH used during on-peak billing period	~~13.227¢~~ *13.879¢* per KWH
All KWH used during off-peak billing period	~~4.940 ¢~~ *5.216¢* per KWH

SPECIAL TERMS AND CONDITIONS

The Company added the following paragraph:

This tariff is available for single-phase, residential service. Where the residential customer requests three-phase service, this tariff will apply if the residential customer pays to the Company the difference between constructing single-phase service and three-phase service. Where motors or heating equipment are used for commercial or industrial purposes, the applicable general service tariff will apply to such service.

TARIFF R.S. – T.O.D.2
(Experimental Residential Service Time-of-Day 2)

AVAILABILITY OF SERVICE.

The Company modified this provision to eliminate the requirement that the multiple-register meter be single phase to receive service under this tariff.

RATE. (Tariff Code 027)

Service Charge	~~$ 11.45~~ *18.70* per month
Energy Charge:	
All KWH used during Summer on-peak billing period	~~11.406¢~~ *10.885¢* per KWH
All KWH used during Winter on-peak billing period	~~13.829¢~~ *12.132¢* per KWH
All KWH used during off-peak billing period	~~7.399¢~~ *8.309¢* per KWH

TARIFF S.G.S.
(Small General Service)

AVAILABILITY OF SERVICE

The Company modified this provision to limit its availability to metered secondary distribution service. The Company also provided a grandfather provision stating that customers not meeting the requirements for coverage under this tariff will only be permitted to continue service under this tariff at the premise occupied for continuous service beginning no later than January 22, 2015.

RATE. (Tariff Codes 211, 212)

Service Charge	~~$11.50~~ *$ 19.50* per month
Energy Charge:	
First 500 KWH per month	~~13.160¢~~ *11.500¢* per KWH
All Over 500 KWH per month	~~7.116¢~~ *7.057¢* per KWH

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

RATE. (Tariff Code 225)

Service Charge	~~$15.40~~ *$19.50* per month
Energy Charge:	
All KWH used during on-peak billing period	~~15.326~~ ¢ *13.755¢* per KWH
All KWH used during off-peak billing period	~~4.940~~ ¢ *5.216¢* per KWH

OPTIONAL UNMETERED SERVICE PROVISION.

RATE. (Tariff Codes 204 (Metered), 213 (Unmetered))

Customer Charge	~~$7.50~~ *$15.50* per month
Energy Charge:	
First 500 KWH per month	~~13.160¢~~ *11.500¢* per KWH
All Over 500 KWH per month	~~7.116¢~~ *7.057¢* per KWH

TARIFF S.G.S – T.O.D
(Small General Service Time-of-Day)

AVAILABILITY OF SERVICE.

The Company modified this provision to clarify that this was no longer an "experimental" customer class and to eliminate the maximum 12 month average demand requirement. The Company also provided a grandfather provision stating that customers not meeting the requirements for coverage under this tariff will only be permitted to continue service under this tariff at the premise occupied for continuous service beginning no later than January 22, 2015.

RATE. (Tariff Code 227)

Service Charge	~~$14.95~~ *$19.50* per month
Energy Charge:	
All KWH used during Summer on-peak billing period	~~13.530¢~~ *11.126¢* per KWH
All KWH used during Winter on-peak billing period	~~15.553¢~~ *12.020¢* per KWH
All KWH used during off-peak billing period	~~8.700¢~~ *8.476¢* per KWH

TARIFF M.G.S.
(Medium General Service)

AVAILABILITY OF SERVICE.

The Company has clarified that for certain customers receiving service on or before January 22, 2015 with a secondary voltage and an average monthly demand of less than 10kW will be served under Tariff S.G.S.

RATE.

	Service Voltage		
	Secondary	Primary	Subtransmission
Tariff Code	215, 216, 218	217, 220	236
Service Charge per Month	$ ~~13.50~~ *19.50*	~~$ 25.00~~ *50.00*	$ ~~182.00~~ *364.00*
Demand Charge per KW	$ ~~1.64~~ *2.05*	$ ~~1.59~~ *1.99*	$ ~~1.55~~ *1.96*
Energy Charge:			
KWH equal to 200 times KW of monthly billing demand	~~9.862¢~~ *10.072¢*	~~9.054¢~~ *9.245¢*	~~8.361¢~~ *8.538¢*
KWH in excess of 200 times KW of monthly billing demand	~~8.460¢~~ *8.639¢*	~~8.098¢~~ *8.270¢*	~~7.851¢~~ *8.018¢*

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the sum of the service charge plus the demand charge multiplied by 6 KW. The minimum monthly charge for Industrial and coal mining customers contracting for 3-phase service after October 1, 1959 shall be ~~$6.84~~ $ *8.55* per KW of monthly billing demand.

RECREATIONAL LIGHTING SERVICE PROVISION.

RATE. (Tariff Code 214)

Service Charge	$ ~~10.50~~ $ *19.50* per month
Energy Charge	~~9.004¢~~ *10.000¢* per KWH

LOAD MANAGEMENT TIME-OF-DAY PROVISIONS. (Tariff Code 223)

RATE.

Service Charge	$ ~~3.00~~ $ *3.85* per month
Energy Charge:	
All KWH used during on-peak billing period	~~14.801¢~~ *15.757¢* per KWH
All KWH used during off-peak billing period	~~5.130¢~~ *5.491¢* per KWH

TERM OF CONTRACT

The Company has revised this provision to indicate that contracts may be required of any customer taking service under this tariff regardless of the level of normal maximum demand.

TARIFF M.G.S. – T.O.D.
(Medium General Service Time-of-Day)

RATE. (Tariff Code 229)

Service Charge	~~$ 14.30~~ $ *19.50* per month
Energy Charge:	
All KWH used during on-peak billing period	~~14.801¢~~ *15.757¢* per KWH
All KWH used during off-peak billing period	~~5.130¢~~ *5.491¢* per KWH

TARIFF L.G.S.
(Large General Service)

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	240, 242	244, 246	248	250
Service Charge per Month	$ 85.00	$ 127.50	~~$ 535.50~~ *661.65*	$ ~~535.50~~ *661.65*
Demand Charge per KW	$ ~~4.02~~ *5.03*	$ ~~3.89~~ *4.89*	$ ~~3.80~~ *4.83*	~~$ 3.76~~ *4.75*
Excess Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46
Energy Charge per KWH	~~7.795¢~~ *8.056¢*	~~6.514¢~~ *6.851¢*	~~4.942¢~~ *4.670¢*	~~4.644¢~~ *4.579¢*

LOAD MANAGEMENT TIME-OF-DAY PROVISION.

RATE. (Tariff Code 251)

Service Charge	$ ~~81.00~~ $ *85.00* per month
Energy Charge:	
All KWH used during on-peak billing period	~~12.971¢~~ *13.164¢* per KWH
All KWH used during off-peak billing period	~~5.116¢~~ *5.471¢* per KWH

TARIFF L.G.S. – T.O.D.
(Large General Service Time-of-Day)

RATE.

	Service Voltage			
	Secondary	Primary	Subtransmission	Transmission
Tariff Code	256	257	258	259
Service Charge per Month	$ 85.00	$ 127.50	$ ~~535.50~~ *661.65*	$ ~~535.50~~ *661.65*
Demand Charge per KW	$ ~~7.64~~ *10.20*	$ ~~4.58~~ *7.35*	$ ~~0.24~~ *1.08*	$ ~~0.15~~ *1.07*
Excessive Reactive Charge per KVA	$ 3.46	$ 3.46	$ 3.46	$ 3.46
On-Peak Energy Charge per KWH	~~9.778¢~~ *8.481¢*	~~7.959¢~~ *8.187¢*	~~7.729¢~~ *8.098¢*	~~7.655¢~~ *8.002¢*
Off-Peak Energy Charge per KWH	~~4.116¢~~ *4.533¢*	~~3.965¢~~ *4.411¢*	~~3.891¢~~ *4.374¢*	~~3.854¢~~ *4.334¢*

TARIFF C.S.-I.R.P.
(Contract Service – Interruptible Power)

AVAILABILITY OF SERVICE.

In accordance with the Stipulation and Settlement Agreement in Case No. 2012-00578, the Company modified this provision to increase the total contract capacity for all customers served under this tariff to 75,000 kW.

RATE. (Tariff Code 321)

In accordance with the Stipulation and Settlement Agreement in Case No. 2012-00578, the Company added the following to this provision:

Credits under this tariff of $3.68/kW/month will be provided for interruptible load that qualifies under PJM's rules as capacity for the purpose of the Company's FRR obligation.

TARIFF M.W.
(Municipal Waterworks)

RATE. (Tariff Code 540)

Service Charge	$ 22.90 per month
Energy Charge:	
All KWH Used Per Month	~~8.300¢~~ *8.601¢* per KWH

MINIMUM CHARGE.

This tariff is subject to a minimum monthly charge equel to the sum of the service charge plus ~~$4.10~~ $ *8.20* per KVA as determined from customer's total connected load.

TARIFF O.L.
(Outdoor Lighting)

RATE.

A. OVERHEAD LIGHTING SERVICE

Tariff Code			
	1.	High Pressure Sodium	
094		100 watts (9,500 Lumens)	$ ~~8.75~~ *9.65* per lamp
113		150 watts (16,000 Lumens)	$ ~~9.90~~ *10.95* per lamp
097		200 watts (22,000 Lumens)	$ ~~12.20~~ *13.45* per lamp
103		250 watts (28,000 Lumens)	$ ~~16.35~~ *18.10* per lamp
098		400 watts (50,000 Lumens)	$ ~~19.15~~ *21.05* per lamp
	2.	Mercury Vapor	
093*		175 watts (7,000 Lumens)	$ ~~9.75~~ *10.75* per lamp
095*		400 watts (20,000 Lumens)	$ ~~16.85~~ *18.60* per lamp

Company will provide lamp, photo-electric relay control equipment, luminaries and upsweep arm not over six feet in length, and will mount same on an existing pole carrying secondary circuits.

B. POST-TOP LIGHTING SERVICE

Tariff Code			
	1.	High Pressure Sodium	
111		100 watts (9,500 Lumens)	$ ~~13.10~~ *14.45* per lamp
122		150 watts (16,000 Lumens)	$ ~~21.45~~ *23.70* per lamp
121		100 watts Shoe Box (9,500 Lumens)	$ ~~20.00~~ *33.50* per lamp
120		250 watts Shoe Box (28,000 Lumens)	$ ~~24.00~~ *50.05* per lamp
126		400 watts Shoe Box (50,000 Lumens)	$ ~~27.90~~ *44.10* per lamp
	2.	Mercury Vapor	
099*		175 watts (7,000 Lumens)	$ ~~11.20~~ *12.30* per lamp

*Effective June 29, 2010 and thereafter these lamps are not evailable for new installations.

Company will provide lamp, photo-electric relay control equipment, luminaries, post, and installation including underground wiring for a distance of thirty feet from the Company's existing secondary circuits.

C. FLOOD LIGHTING SERVICE

Tariff Code			
	1.	High Pressure Sodium	
107		200 watts (22,000 Lumens)	$ ~~13.60~~ *15.00* per lamp
109		400 watts (50,000 Lumens)	$ ~~18.85~~ *20.80* per lamp
	2.	Metal Halide	
110		250 watts (20,500 Lumens)	~~$18.20~~ *20.10* per lamp
116		400 watts (36,000 Lumens)	$ ~~24.10~~ *26.60* per lamp
131		1000 watts (110,000 Lumens)	$ ~~52.20~~ *67.35* per lamp
130		250 wetts Mongoose (19,000 Lumens)	$ ~~21.90~~ *25.30* per lamp
136		400 watts Mongoose (40,000 Lumens)	$ ~~25.50~~ *30.30* per lamp

Company will provide lamp, photoelectric relay control equipment, luminaries, mounting bracket, and mount same on an existing pole carrying secondary circuits.

When new or additional facilities, other than those specified in Paragraphs A, B, and C, are to be installed by the Company, the customer in addition to the monthly charges, shall pay in advance the installation cost (labor and material) of such additional facilities extending from the nearest or most suitable pole of the Company to the point designated by the customer for the installation of said lamp, except that customer may, for the following facilities only, elect, in lieu of such payment of the installation cost to pay:

Wood pole	$ ~~2.85~~ *3.15* per month
Overhead wire span not over 150 feet	$ ~~1.60~~ *1.75* per month
Underground wire lateral not over 50 feet	$ ~~6.25~~ *6.90* per month

(Price includes pole riser and connections)

TERM OF INITIAL SERVICE.

The Company modified the tariff to provide that if early termination is requested, the customer will be billed for the remainder of the 12 month period.

TARIFF S.L.
(Street Lighting)

RATE. (Tariff Code 528)

A. Overhead Service on Existing Distribution Poles

1. High Pressure Sodium		
100 wetts (9,500 lumens)	$	~~7.25~~ *8.05* per lamp
150 watts (16,000 lumens)	$	~~8.30~~ *9.25* per lamp
200 watts (22,000 lumens)	$	~~10.30~~ *11.45* per lamp
400 watts (50,000 lumens)	$	~~16.05~~ *17.80* per lamp

B. Service on New Wood Distribution Poles

1. High Pressure Sodium		
100 watts (9,500 lumens)	$	~~10.25~~ *11.35* per lamp
150 watts (16,000 lumens)	$	~~11.40~~ *12.60* per lamp
200 watts (22,000 lumens)	$	~~13.15~~ *14.60* per lamp
400 watts (50,000 lumens)	$	~~18.45~~ *20.45* per lamp

C. Service on New Metal or Concrete Poles*

1. High Pressure Sodium		
100 watts (9,500 lumens)	$	~~18.90~~ *20.95* per lamp
150 watts (16,000 lumens)	$	~~19.85~~ *22.00* per lamp
200 watts (22,000 lumens)	$	~~25.25~~ *28.00* per lamp
400 watts (50,000 lumens)	$	~~27.45~~ *30.45* per lamp

*Effective June 29, 2010 and thereafter these lamps are not available for new installations.

TARIFF C.A.T.V.
(Cable Television Pole Attachment)

AVAILABILITY OF SERVICE.

The Company modified this provision to provide a definition for "attachment."

RATE.

Charge for attachments on a two-user pole	$ 7.21 per ~~pole/year~~ *attachment per year*
Charge for attachments on a three-user pole	$ 4.47 per ~~pole/year~~ *attachment per year*

The Company added a definition of "two-user pole" end "three-user pole" to this provision.

DELAYED PAYMENT CHARGE.

The Company extendod the payment due date from 15 to 30 days after the date of the bill.

POLE SUBJECT TO ATTACHMENT.

The Company extended the time for the Company to respond to applications for pole usage from 21 to 45 days.

UNAUTHORIZED ATTACHMENTS.

The Company reserves the right to make periodic inspections for unauthorized use.

INSURANCE.

The Company extended the time for written notice of any cancellation of or material change in a customer's policy by its insurance carrier. Notice must now be provided by the carrier 30 days, instead of 15 days, prior to the revision or cancellation.

CHARGES AND FEES.

The Company clarified that the charges under this tariff are based on the number of attachments and are to be paid annually, not semi-annually.

ADVANCE BILLING.

In the event the time for any payment is not specified, such payment shall be due 30 days, instead of 15 days, from the date of the invoice.

DEFAULT OR NON-COMPLIANCE.

The Company clarified that the remedies identified in this provision were in addition to all other remedies available in the tariff.

TARIFF COGEN/SPP I
(Cogeneration and/or Small Power Production – 100kW or Less)

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be es follows:

Option 1 - *Not Applicable.*
~~Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.~~

Options 2 & 3 - Where meters are used to measure the excess or totel energy and average on-peak capacity purchased by the Company:

	Single Phase	Polyphase
Standard Measurement	$ ~~6.75~~ $ *8.50*	~~$7.75~~ $ *11.10*
T.O.D. Measurement	$ ~~7.15~~ $ *9.05*	~~$8.10~~ $ *11.40*

The Company eliminated the requirement that the customer install and pay a monthly facilities charge for a detent under Option 1.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the alectrical energy delivered to the Company:

Standard Meter - All KWH	~~2.90¢~~ *3.79¢* KWH
T.O.D. Meter	
On-Peak KWH	~~3.06¢~~ *4.64¢* KWH
Off-Peak KWH	~~2.78¢~~ 3.18¢ KWH

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly contract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standard energy meters are used,

A. $ ~~2.84~~ *3.70* KW/month, times the lowest of:

(1) monthly contract capacity, or

(2) current month metered average capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used,

B. ~~$6.82~~ *8.87* KW/month, times the lowest of:

(1) on-peak contract capacity, or

(2) current month on-peak metered averege capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by ~~327~~, *305* or

(3) lowest on-peak average capacity metered during tha previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as epproved by the Commission.

TARIFF COGEN/SPP II
(Cogeneration and/or Small Power Production – Over 100kW)

ADDITIONAL CHARGES.

There shall be additional charges to cover the cost of special metering, safety equipment and other local facilities installed by the Company due to COGEN/SPP facilities, as follows:

Monthly Metering Charge

The additional monthly charge for special metering facilities shall be as follows:

Option 1 - *Not Applicable.*
~~Where the customer does not sell electricity to the Company, a detent shall be used on the energy meter to prevent reverse rotation. The cost of such meter alteration shall be paid by the customer as part of the Local Facilities Charge.~~

Options 2 & 3- Where meters are used to measure the excess or total energy and avarage on peak capacity purchased by the Company:

	Single Phase	Polyphase
Standard Measurement	$ ~~6.75~~ *8.50*	$ ~~7.75~~ *11.10*
T.O.D. Measurement	$ ~~7.15~~ *9.05*	$ ~~8.10~~ *11.40*

The Company eliminated the requirement that the customer install and pay a monthly facilities charge for a detent under Option 1.

MONTHLY CREDITS OR PAYMENTS FOR ENERGY AND CAPACITY DELIVERIES.

Energy Credit

The following credits or payments from the Company to the customer shall apply for the electrical energy delivered to the Company:

Standard Meter - All KWH	~~2.90¢~~ *3.79¢* KWH
T.O.D. Meter	
On-Peak KWH	~~3.06¢~~ *4.64¢* KWH
Off-Peak KWH	~~2.78¢~~ *3.18¢* KWH

Capacity Credit

If the customer contracts to deliver or produce a specified excess or total average capacity during the monthly billing period (monthly centract capacity), or a specified excess or total average capacity during the on-peak monthly billing period (on-peak contract capacity), then the following capacity credits or payment from the Company to the customer shall apply:

If standerd energy meters are used,

A. $~~2.84~~ *3.70*/KW/ month, times the lowest of:

(1) monthly contract capacity, or

(2) current month metered everage capacity, i.e., KWH delivered to the Company or produced by COGEN/SPP facilities divided by 730, or

(3) lowest average capacity metered during the previous two months if less than monthly contract capacity.

If T.O.D. energy meters are used,

B. $~~6.82~~ *8.87*/KW/month, times the lowest of:

(1) on-peak centract capacity, or

(2) current month on-peak metered average capacity, i.e., on-peak KWH delivered to the Company or produced by COGEN/SPP facilities divided by ~~730~~ *305*, or

(3) lowest on-peak average capacity metered during the previous two months, if less than on-peak contract capacity.

The above energy and capacity credit rates are subject to revisions from time to time as approved by the Commission.

TARIFF S.S.C.
(System Sales Clause)

RATE.

The Company has modified this provision to eliminate the Interim System Sales Adjustment Factor that was authorizod by the Commission in Case No. 2012-00578.

The Company has further modified this provision to address termination of the AEP East Interconnection Agreement:

2. The net revenue from KPCo's sales to non-associated companies as reported in the FERC Energy Regulatory Commission's Uniform System of Accounts under Account 447, Sales for Resale, shall consist of and be derived as follows:

a. KPCo's total revenues from system sales as recorded in Account 447, less b. and c. below.

b. KPCo's total out-of-pocket costs incurred in supplying the power and energy for the sales in a. above.

The out-of-pocket costs include all operating, maintenance, tax, transmission losses and other expenses that would not have been incurred if the power and energy had not been supplied for such sales, including demand and energy charges for power and energy supplied by Third Parties.

c. KPCo's environmental costs allocated to non-associated utilities in the Company's Environmental Surcharge Report.

3. The base monthly net revenues from system sales are as follows:

Billing Month	System Sales (Total Company Basis)	
January	$ ~~528,886~~	*1,560,360*
February	~~335,167~~	*1,335,811*
March	~~1,530,409~~	*1,296,845*
April	~~1,371,521~~	*1,152,503*
May	~~1,307,472~~	*1,170,480*
June	~~767,124~~	*1,106,499*
July	~~616,234~~	*1,322,384*
August	~~2,136,652~~	*1,031,319*
September	~~1,850,577~~	*1,038,816*
October	~~1,739,665~~	*1,088,125*
November	~~1,538,455~~	*1,123,099*
December	~~1,568,121~~	*1,073,722*
	~~$15,290,863~~	$14,299,964

TARIFF T.S.
(Temporary Service)

AVAILABILITY OF SERVICE.

The Company clarified that residential customers taking service under this tariff will receive 100 amp service and that all other customer classes will be supplied at the voltage levels applicable to that customer class.

RATE.

The Company has added a new Tariff Code (Tariff Code 019) for customers receiving temporary service.

TERM.

The Company modified this provision to indicate that temporary service is available for an initial term of 180 days and a 90 day extension in the Company's discretion.

TARIFF D.S.M.C.
(Demand-Side Management Adjustment Clause)

The Company submitted proposed revisions to its demand side management programs to the Commission in Case No. 2014-00271. Upon a final order in that case, the Company will make any necessary revisions to this tariff pursuant to the Commission's order.

TARIFF N.U.G.
(Non-Utility Generator)

Changes were made to remove the monthly transmission and distribution rates table. Generation, transmission, and distribution rates will be included in the customer contract.

TARIFF N.M.S.
(Net Metering Service)

Changes were made to update the contact information for customers wishing to participate in net metering services.

TARIFF C.C.
(Capacity Charge)

RATE.

	Service Tariff: All Other	Service Tariff: ~~C.I.P.-T.O.D.~~ I.G.S.
Energy Charge per KWH per month	$ ~~0.000970~~ *0.001182*	$ ~~0.000667~~ *0.000659*

RATE CALCULATION.

The Company further added a provision to allow the Company to adjust the capacity charge annually:

7. The capacity charge will be adjusted annually to recover amounts authorized by the Commission.

The annual adjustment shall be determined as follows:

A. Calculate the revenue over / under collection for the previous 12 month period. REVbilled – REVsettlement = REVdiff

B. Calculate the revenue requirement for the upcoming 12 month period, REVsettlement + REVdiff = REVauthorized

C. Calculate Capacity Charge Rates for the upcoming 12 month period,

$$\text{IGS Capacity Charge} = \frac{\text{REVauthorized x (REVIGS / REVTotal)}}{\text{kWhIGS}}$$

$$\text{All Other Capacity Charge} = \frac{\text{REVauthorized x (REVAll Other / REVTotal)}}{\text{kWhAll Other}}$$

Where:

"REVTotal" is the total revenue billed during the most recently available 12 month period.

"REVIGS" is the total IGS customer class revenue billed during the most recently available 12 month period.

"REVAll Other" is the revenue billed from all other customer classes during the most recently available 12 month period.

"kWhIGS" is the IGS customer class total kWh billed during the most recently available 12 month period.

"kWhAll Other" is the total kWh billed to all customer classes other than IGS during the most recently available 12 month period.

"REVbilled" is the total capacity charge revenue billed during the most recently available 12 month period.

"REVsettlement" is the $6.2 million amount authorized to be billed during the 12 month period.

"REVdiff" is the difference between capacity charge revenues billed and what the Company is authorized to collect in a 12 month period.

"REVauthorized" is the capacity charge amount to be billed over the upcoming 12 month period.

8. The annual Capacity Charge Adjustment shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

TARIFF E.S.
(Environmental Surcharge)

RATE.

The Company has modified this provision to eliminate the interim Environmental Surcharge Factor that was authorized by the Commission in Case No. 2012-00578 and to provide for the recovery of costs associated with the Mitchell flue gas desulfurization unit through the Environmental Surcharge in accordance with the Commission's Order in Case No. 2012-00578.

2.~~3.~~ Base Period Revenue Requirement, BRR

BRR = The Following Monthly Amounts:

Billing Month	Base Net Environmental Costs	
JANUARY	$ ~~3,991,163~~	$ *2,750,919*
FEBRUARY	~~3,590,910~~	$ *2,738,884*
MARCH	~~3,651,374~~	$ *2,851,531*
APRIL	~~3,647,040~~	$ *2,909,965*
MAY	~~3,922,590~~	$ *2,897,250*
JUNE	~~3,627,274~~	$ *2,835,973*
JULY	~~3,805,325~~	$ *3,567,407*
AUGUST	~~4,068,830~~	$ *3,319,549*
SEPTEMBER	~~3,740,010~~	$ *3,378,515*
OCTOBER	~~3,260,302~~	$ *3,097,929*
NOVEMBER	~~2,706,040~~	$ *2,994,579*
DECEMBER	~~4,074,321~~	$ *2,996,160*
	$ ~~44,185,079.~~	$ *36,338,660*

The Company has revised the formula for calculating the Current Period Revenue Requirement as shown below.

3. ~~4.~~ Current Period Revenue Requirement, CRR

CRR=[((RBKP(c))(RORKP(c))/12) + OEKP(c) + [((RBIM(c)) (RORIM(c))/12) + OEIM(c)] (.15) – AS]

Where:

RBKP(C)	=	Environmental Compliance Rate Base for ~~Big Sandy~~. *Mitchell*.
RORKP(C)	=	Annual Rate of Return on ~~Big Sandy~~ *Mitchell* Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
OEKP(C)	=	Monthly Pollution Control Operating Expenses for ~~Big Sandy~~. *Mitchell*.
RBIM(C)	=	Environmental Compliance Rate Base for Rockport.
RORIM(C)	=	Annual Rate of Return on Rockport Rate Base; Annual Rate divided by 12 to restate to a Monthly Rate of Return.
OEIM(C)	=	Monthly Pollution Control Operating Expenses for Rockport.
AS	=	Net proceeds from the sale of *Title IV* and *CSAPR* SO_2 emission allowances, ERCs, and NOx emission allowances, reflected in the month of receipt. ~~The SO_2 allowance sales can be from either EPA Auctions or the AEP Interim Allowance Agreement Allocations.~~

"KP(C)" identifies components from the ~~Big Sandy~~ *Mitchell* Units – Current Period, and "IM(C)" identifies components from the Indiana Michigan Power Company's Rockport Units – Current Period.

The Rate Base for both Kentucky Power and Rockport should reflect the current costs associated with the 1997 Plan, and the 2003 Plan, the *2005 Plan, the 2007 Plan and the 2014 Plan*. The Rate Base for Kentucky Power should also include a cash working capital allowance based on the 1/8 formula approach, due to the inclusion of Kentucky Power's accounts receivable financing in the capital structure and weighted average cost of capital. The Operating Expenses for both Kentucky Power and Rockport should reflect the current operating expenses associated with the 1997 Plan, the 2003 Plan, the 2005 Plan, ~~and~~ the 2007 Plan, *and the 2014 Plan*.

The Rate of Return for Kentucky Power is ~~10.50%~~ *10.62%* rate of return on equity as authorized by the Commission in its ~~June 29, 2010~~ Order *Dated XXXXXXXXX* in Case No. *2014-00396* ~~2009-00459 at page 6~~.

The Rate of Return for Rockport should reflect the requirements of the Rockport Unit Power Agreement.

Net Proceeds from the sale of emission allowances and ERCs that reflect net gains will be a reduction to the Current Period Revenue Requirement, while net losses will be an increase.

The Current Period Revenue Requirement will reflect the balances and expenses as of the Expense Month of the filing.

The Company has also revised the Revenue Allocation and Environmental Surcharge Factors as follows as authorized by the Commission in Case No. 2012-00578.

4. Revenue Allocation

$$\text{Residential Allocation RA(m)} = \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(m)} = \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(m) = the expense month
(b) = most recont calendar year revenues

5. Environmental Surcharge Factor

$$\text{Residential Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m) * RA(m)}}{\text{KY RR(m)}}$$

$$\text{All Other Monthly Environmental Surcharge Factor} = \frac{\text{Net KY Retail E(m) * AO(m)}}{\text{KY OR(m)- KY OF(m)}}$$

Where:

Net KY Retail E(m) = Monthly E(m) allocated to Kentucky Retail Customers, net of Over/(Under) Recovery Adjustment; Allocation based on Percentage of Kentucky Retail Revenues to Total Company Revenues in the Expense Month.

(For purposes of this formula, Total Company Revenues do not include Non -Physical Revenues.)

RR(m) = Kentucky Residential Retail Revenues for the Expense Month.

OR(m) = Kentucky All Other Classes Retail Revenues for the Expense Month

OF(m) = Kentucky All Other Classes Fuel Revenues for the Expense Month

The Company also made changes to the list of projects for which Kentucky Power can recover its costs through this tariff as a result of the termination of the Pool Agreement, changes in environmental regulations, and the Commission's Order in Case No. 2012-00578 to remove references to environmental projects at generating facilities that Kentucky Power does not own or with which it does not have a long-term contract, to add allowances necessary for compliance with the Cross State Air Pollution Rule, to add projects consistent with the Company's ownership of an undivided 50% interest in the Mitchell Generating Station, and to remove projects at the Big Sandy Plant.

RIDER A.F.S.
(Alternate Feed Service Rider)

TRANSFER SWITCH PROVISION.

Existing AFS customers, who receive basic service at primary voltage and are served via a Company-owned transfer switch and control module, may elect for the Company to continue ownership of the transfer switch. When the Company-owned transfer switch and/or control module requires replacement, and the customer desires to continue the AFS, the customer shall pay the Company the total cost to replace such equipment which shall be grossed up for federal and state taxes, assessment fees and gross receipts taxes. In addition, the customer shall pay a monthly rate of $~~13.57~~ $*14.25* for the Company to annually test the transfer switch/control module and the customer shall reimburse the Company for the actual costs involved in maintaining the Company-owned transfer switch and control module.

MONTHLY AFS CAPACITY RESERVATION DEMAND CHARGE.

The Monthly AFS Capacity Reservation Demand Charge for the reservation of distribution station and primary lines is $~~4.34~~ $*6.25* per kW.

TARIFF P.P.A.
(Purchase Power Adjustment)

RATE.

The Company modified the tariff provision and the monthly rate formula to allow the Company to recover the full cost of purchased power unrelated to forced generation or transmission outages:

2. The net costs of any power purchased shall exclude costs recovered through the Fuel Adjustment Clause and shall be computed as the sum of the following items:

a. PPA(m) = The cost of power purchased by the Company through new Purchase Power Agreements (PPAs). All new PPAs shall be approved by the Commission to the extent required by KRS 278.300.
b. RP(m) = The cost of fuel related substitute generation less the cost of fuel which would have been used in plants suffering forced generation or transmission outages.
c. *PE(m)= The cost of power purchased unrelated to forced generation or transmission outages that are calculated in accordance with the peaking unit equivalent methodology.*
d. CSIRP(m) = The cost of any credits provided to customers under Tariff C.S.-I.R.P. for interruptible service.

Monthly P(m) = PPA(m) + RP(m)+*PE(m)* + CSIRP(m)

TARIFF A.T.R.
(Asset Transfer Rider)

RATE.

The Company modified this provision to clarify that this rider will remain in effect until the Company recovers during the year new base rates are set the pro rata share of the $44 million annual revenue requirement under Tariff A.T.R. The Company has updated the descriptive language in each customer class tariff where the Tariff A.T.R. applies.

TARIFF E.D.R.
(Economic Development Rider)

The Company submitted the proposed Economic Development Rider to the Commission for its approval in Case No. 2014-00336. Upon a final order in that case, the Company will make any necessary revisions to this tariff pursuant to the Commission's order.

NEW TARIFFS

Kentucky Power is proposing the following new tariffs. For each customer class tariff where these new tariffs apply, language has been added to identify their applicability.

TARIFF I.G.S.
(Industrial General Service)

AVAILABILITY OF SERVICE.

Available for commercial and industrial customers with contract demands of at least 1,000 KW. Customers shall contract for a definite amount of electrical capacity in kilowatts, which shall be sufficient to meet normal maximum requirements.

RATE.

	Secondary	Primary	Service Voltage Subtransmission	Transmission
Tariff Code	356	358/370	359/371	360/372
Service Charge per month	$ 276.00	$ 276.00	$ 794.00	$ 1,353.00
Demand Charge per KW				
Of monthly on-peak billing demand	$ 20.69	$ 17.46	$ 10.74	$ 10.45
Of monthly off-peak billing demand	$ 1.13	$ 1.10	$ 1.08	$ 1.07
Energy Charge per KWH	3.398¢	3.279¢	3.242¢	3.204¢

Reactive Demand Charge for each kilovar of maximum leading or lagging reactive demand in excess of 50 percent of the KW of monthly metered demand $0.69/ KVAR

For the purpose of this tariff, the on-peak billing period is defined as 7:00 AM to 9:00 PM for all weekdays, Monday through Friday. The off-peak billing period is defined as 9:00 PM to 7:00 AM for all weekdays and all hours of Saturday and Sunday.

MINIMUM DEMAND CHARGE.

The minimum demand charge shall be equal to the minimum billing demand times the following minimum demand rates:

Secondary	Primary	Subtransmission	Transmission
$22.06/KW	$18.80 /KW	$12.07/KW	$11.76/KW

The minimum billing demand shall be the greater of 60% of the contract capacity set forth on the contract for electric service or 60% of the highest billing demand, on-peak or off-peak, recorded during the previous eleven months.

MINIMUM CHARGE.

This tariff is subject to a minimum charge equal to the Service Charge plus the Minimum Demand Charge.

FUEL ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Fuel Adjustment Factor per KWH calculated in compliance with the Fuel Adjustment Clause contained in Sheet Nos. 5-1 and 5-2 of this Tariff Schedule.

SYSTEM SALES CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a System Sales Factor per KWH calculated in compliance with the System Sales Clause contained in Sheet Nos. 19-1 and 19-2 of this Tariff Schedule.

DEMAND-SIDE MANAGEMENT ADJUSTMENT CLAUSE.

Bills computed according to the rates set forth herein will be increased or decreased by a Demand-Side Management Adjustment Clause Factor per KWH calculated in compliance with the Demand-Side Management Adjustment Clause contained in Sheet Nos. 22-1 through 22-13 of this Tariff Schedule, unless the customer is an industrial who has elected to opt-out in accordance with the terms pursuant to the Commission's Order in Case No. 95-427.

ASSET TRANSFER RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by an Asset Transfer Adjustment Factor based on a percent of revenue in compliance with the Asset Transfer Rider contained in Sheet No. 36-1 through 36-2 of this Tariff Schedule. The Asset Transfer Adjustment Factor will be applied to bills until such time as the pro rata amount (computed on a 365-day annual basis) authorized to be recovered via Tariff A.T.R. in the Stipulation and Settlement Agreement, approved as modified by the Commission by its order dated October 7, 2013 in Case No. 2012-00578, has been recovered.

BIG SANDY RETIREMENT RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy Retirement Rider Adjustment Factor based on a percent of revenue in compliance with the Big Sandy Retirement Rider contained in Sheet No. 38-1 through 38-2 of this Tariff Schedule.

BIG SANDY I OPERATION RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a Big Sandy 1 Operation Rider Adjustment Factor per kW and/or kWh calculated in compliance with the Big Sandy 1 Operation Rider contained in Sheet Nos. 39-1 through 39-2 of this Tariff Schedule.

PURCHASE POWER ADJUSTMENT.

Bills computed according to the rates set forth herein will be increased or decreased by a Purchase Power Adjustment Factor based on a percent of revenue in compliance with the Purchase Power Adjustment contained in Sheet No. 35-1 of this Tariff Schedule.

ENVIRONMENTAL SURCHARGE.

Bills computed according to the rates set forth herein will be increased or decreased by an Environmental Surcharge adjustment based on a percent of revenue in compliance with the Environmental Surcharge contained in Sheet Nos. 29-1through 29-5 of the Tariff Schedule.

CAPACITY CHARGE.

Bills computed according to the rates set forth herein will be increased by a Capacity Charge Factor per KWH calculated in compliance with the Capacity Charge Tariff contained in Sheet No. 28-1 through 28-2 of this Tariff Schedule.

P.J.M. RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a PJM Rider per kW and/or kWh calculated in compliance with the PJM Rider contained in Sheet Nos. 24-1 through 24-3 of this Tariff Schedule.

KENTUCKY ECONOMIC DEVELOPMENT SURCHARGE.

Applicable to all customers. Bills computed according to the rates set forth herein shall be increased by a KEDS charge of $0.15 per month and shall be shown on the customers' bills as a separate line item. The KEDS charge will be applied to all customer electric bills rendered during the billing cycles commencing July 2015 and continue until otherwise directed by the Public Service Commission.

HOME ENERGY ASSISTANCE PROGRAM (HEAP) CHARGE.

Applicable to all residential customers. Bills computed according to the rates set forth herein shall be increased by a HEAP charge of 15¢ per meter per month and shall be shown on the residential customers bill as a separate line item. The Home Energy Assistance Program charge will be applied to all residential electric bills rendered during the billing cycles commencing July 2010 and continue until otherwise directed by the Public Service Commission.

NERC COMPLIANCE AND CYBERSECURITY RIDER.

Bills computed according to the rates set forth herein will be increased or decreased by a NERC Compliance and Cyber-security Rider Adjustment Factor per kW and/or kWh calculated in compliance with the NERC Compliance Cybersecurity Rider contained in Sheet Nos. 40-1 through 40-3 of this Tariff Schedule.

DELAYED PAYMENT CHARGE.

Bills under this tariff are due and payable within fifteen (15) days of the mailing date. On all accounts not paid in full by the next billing date, an additional charge of 5% of the unpaid portion will be made.

METERED VOLTAGE.

The rates set forth in this tariff are based upon the delivery and measurement of energy at the same voltage, thus measurement will be made at or compensated to the delivery voltage. At the sole discretion of the Company, such compensation may be achieved through the use of loss compensating equipment, the use of formulas to calculate losses or the application of multipliers to the metered quantities. In such cases, the metered KWH and KVA values will be adjusted for billing purposes. If the Company elects to adjust KWH and KW based on multipliers, the adjustment shall be in accordance with the following:

(1) Measurements taken at the low-side of a Customer-owned transformer will be multiplied by 1.01.
(2) Measurements taken at the high-side of a Company-owned transformer will be multiplied by 0.98.

MONTHLY BILLING DEMAND.

The monthly on-peak and off-peak billing demands in KW shall be taken each month as the highest single 15-minute integrated peak in KW as registered by a demand meter during the on-peak and off-peak billing periods, respectively.

The reactive demand in KVARs shall be taken each month as the highest single 15-minute integrated peak in KVARs as registered during the month by a demand meter or indicator.

TERM OF CONTRACT.

Contracts under this tariff will be made for an initial period of not less than two years and shall remain in effect thereafter until either party shall give at least 12 months' written notice to the other of the intention to terminate the contract. The Company reserves the right to require initial contracts for periods greater than two years.

A new initial contract period will not be required for existing customers who change their contract requirements after the original initial period unless new or additional facilities are required.

CONTRACT CAPACITY.

The Customer shall set forth the amount of capacity contracted for ("the contract capacity") in an amount equal to or greater than 1,000 KW in multiplies of 100 KW. The Company is not required to supply capacity in excess of such contract capacity except with express written consent of the Company.

SPECIAL TERMS AND CONDITIONS.

This tariff is subject to the Company's Terms and Conditions of Service.

This tariff is available for resale service to mining and industrial Customers who furnish service to Customer-owned camps or villages where living quarters are rented to employees and where the Customer purchases power at a single point for both the power and camp requirements.

This tariff is also available to Customers having other sources of energy supply, but who desire to purchase standby or back-up electric service from the Company. Where such conditions exist the Customer shall contract for the maximum amount of demand in KW which the Company might be required to furnish, but not less than 1,000 KW. The Company shall not be obligated to supply demands in excess of that contracted capacity. Where service is supplied under the provisions of this paragraph, the billing demand each month shall be the highest determined for the current and previous two billing periods, and the minimum charge shall be as set forth under paragraph "Minimum Charge" above.

A Customer's plant is considered as one or more buildings, which are served by a single electrical distribution system provided and operated by the Customer. When the size of the Customer's load necessitates the delivery of energy to the Customer's plant over more than one circuit, the Company may elect to connect its circuits to different points on the Customer's system irrespective of contrary provisions in Terms and Conditions of Service.

Customer with PURPA Section 210 qualifying cogeneration and/or small power production facilities shall take service under Tariff COGEN/SPP II or by special agreement with the Company.

TARIFF P.J.M.R.
(PJM Rider)

APPLICABLE:

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES: (Tariff Code 390)

Tariff Class	¢/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	0.0000	--
S.G.S. and S.G.S.-T.O.D.	0.0000	--
M.G.S.	0.0000	0.00
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	0.0000	--
L.G.S. and L.G.S.-T.O.D.	0.0000	0.00
L.G.S.-L.M.-T.O.D.	0.0000	0.00
I.G.S. and C.S.-I.R.P	0.0000	0.00
M.W.	0.0000	–
O.L.	0.0000	–
S.L.	0.0000	–

The kWh adjustment factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW adjustment factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS and IGS tariff classes.

The PJM Rider adjustment factor shall be modified annually to reflect the difference between the approved base level of PJM charges and credits and the PJM charges and credits actually experienced.

The PJM Rider adjustment factor shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Adjustment Factor} = \frac{\text{PJME x (BEClass /BETotal) + PJMD x (CPClass /CPTotal)}}{\text{BEClass}}$$

kW Adjustment Factor = 0

For all tariff classes with demand billing:

$$\text{kWh Adjustment Factor} = \frac{\text{PJME x (BEClass /BETotal)}}{\text{BEClass}}$$

$$\text{kW Adjustment Factor} = \frac{\text{PJMD x (CPClass /CPTotal)}}{\text{BDClass}}$$

Where:

1. "PJMD" is the actual (over)/under recovery of annual retail PJM demand-related net costs; calculated by comparing the amount of PJM demand-related net costs in base rates to those retail PJM demand-related net costs actually incurred during the review period.

2. "PJME" is the actual (over)/under recovery of annual retail PJM energy-related net costs; calculated by comparing the amount of PJM energy-related net costs in base rates to those retail PJM energy-related net costs actually incurred during the review period.

3. "BEClass" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.

4. "BDClass" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CPClass" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class (1)	BEClass (2)	CP/kWh Ratio (3)	CPClass (4)=(2)x(3)
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2		0.0236060%	
S.G.S. and S.G.S.-T.O.D.		0.0163937%	
M.G.S.		0.0177002%	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		0.0177002%	
L.G.S. and L.G.S.-T.O.D.		0.0169381%	
L.G.S.-L.M.-T.O.D.		0.0169381%	
I.G.S. and C.S.-I.R.P		0.0130626%	
M.W.		0.0134057%	
O.L.		0.0009431%	
S.L.		0.0009890%	
	BETotal		CPTotal

6, "BETotal" is the sum of the BEClass for all tariff classes.

7. "CPTotal" is the sum of the CPClass for all tariff classes.

The adjustment factor as computed above shall be further modified to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the PJM Rider adjustment revenues.

The annual PJM Rider shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by tha Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

RIDER B.S.R.R.
(Big Sandy Retirement Rider)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D.2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.- I.R.P., M.W., O.L., and S.L.

RATE.

1. Pursuant to the final order of the Kentucky Public Service Commission in Case No. 2012-00578 and the Stipulation and Settlement Agreement dated July 2, 2013 as filed and approved by the Commission, Kentucky Power Company is to recover from retail ratepayers the coal-related retirement costs of Big Sandy Unit 1, the retirement costs of Big Sandy Unit 2 and other site-related retirement costs that will not continue in use on a levelized basis, including a weighted average cost of capital (WACC) carrying cost over a 25 year period beginning when new base rates are set for the Company that include Mitchell Units 1 and 2. The term "Retirement Costs" as used in this agreement are defined as and shall include the net book value, materials and supplies that cannot be used economically at other plants owned by Kentucky Power, and removal costs and salvage credits, net of related ADIT. Related ADIT shall include the tax benefits from tax abandonment losses.

2. The allocation of the levelized revenue requirement (LRR) between residential and all other customers shall be based upon their respective contribution to total retail revenues for the most recent calendar twelve month period, according to the following formula:

$$\text{Residential Allocation RA(m)} = \text{LRR(m)} \times \frac{\text{KY Residential Retail Revenue RR(b)}}{\text{KY Retail Revenue R(b)}}$$

$$\text{All Other Allocation OA(m)} = \text{LRR(m)} \times \frac{\text{KY All Other Classes Retail Revenue OR(b)}}{\text{KY Retail Revenue R(b)}}$$

Where:

(m) = the expense month;

(b) = Most recent available twelve calendar-month period ended December 31.

3. The Residential Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of total revenues, according to the following formula:

$$\text{Residential Asset Transfer Adjustment Factor} = \frac{\text{Net Monthly Residential Allocation NRA(m)}}{\text{Residandial Retail Revenue RR(m)}}$$

Where:

Net Monthly Residential Allocation NRA(m) = Monthly Residential Allocation RA(m), net of Over/(Under) Recovery Adjustment;

Residential Retail Revenue RR(m) = Monthly Retail Revenue for all KY residential classes for the expense month (m).

4. The All Other Classes Asset Transfer Adjustment shall provide for monthly adjustments based on a percent of non-fuel revenues, according to the following formula:

$$\text{All Other Classes Asset Transfer Adjustment Factor} = \frac{\text{Net Monthly All Other Allocation NOA(m)}}{\text{All Other Classes Non-Fuel Retail Revenue ONR(m)}}$$

Where:

Net Monthly All Other Allocation NOA(m) = Monthly All Other Allocation OA(m), net of Over/(Under) Recovery Adjustment;

All Other Classes Non-Fuel Retail Revenue ONR(m) = Monthly Non-Fuel Retail Revenue for all classes other than residential for the expense month (m).

5. The monthly Big Sandy Retirement Rider adjustments shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all the necessary supporting data to justify the amount of the adjustments, which shall include data, and information as may be required by the Commission.

6. Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS61.870 to 61.884

RIDER B.S.1.O.R
(Big Sandy 1 Operation Rider)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., Experimental R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES.

Tariff Class	$/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	$0.00330	–
S.G.S. and S.G.S.-T.O.D.	$0.00272	--
M.G.S.	$0.00141	$0.34
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	$0.00283	–
L.G.S. and L.G.S.-T.O.D.	$0.00139	$0.45
L.G.S.-L.M.-T.O.D.	$0.00276	--
I.G.S. and C.S.-I.R.P.	$0.00139	$0.55
M.W.	$0.00248	--
O.L.	$0.00147	--
S.L.	$0.00147	--

Teriff BS1OR includes all non-fuel operating expenses related to Big Sandy Unit 1 not otherwise included in Tariff S.S.C. or Taritl F.A.C. Tariff BS1OR shall also include a return on and of Big Sandy Unit 1 gas conversion capital when placed in service.

The kWh factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS, and IGS tariff classes.

The Big Sandy Unit 1 Operation Rider factors shall be modified annually to collect the approved annual level of Kentucky retail jurisdictional Big Sandy Unit 1 revenue requirement and any prior review period (over)/under recovery.

The Big Sandy Unit 1 Operation Rider factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Factor} = \frac{\text{BS1E x (BEClass /BETotal) + BS1D x (CPClass /CPTotal)}}{\text{BEClass}}$$

$$\text{kW Factor} = 0$$

For all tariff classes with demend billing:

$$\text{kWh Factor} = \frac{\text{BS1E x (BEClass /BETotal)}}{\text{BEClass}}$$

$$\text{kW Factor} = \frac{\text{BS1D x (CPClass//CPTota)}}{\text{BDClass}}$$

Where:

1. "BS1D" is the actual annual retail Big Sandy Unit 1 demand-related costs, plus any prior review period (over)/under recovery.
2. "BS1E" is the actual annual retail Big Sandy Unit 1 energy-related costs, plus any prior review period (over)/under recovery.
3. "BEClass" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.
4. "BDClass" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.
5. "CPClass" is the coincident peak demand for each tariff class estimated as follows:

Tariff Class (1)	BEClass (2)	CP/kWh Ratio (3)	CPClass (4)=(2)x(3)
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2		0.0236060%	
S.G.S and S.G.S.-T.O.D.		0.0163937%	
M.G.S.		0.0177002%	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		0.0177002%	
L.G.S. and L.G.S.-T.O.D.		0.0169381%	
L.G.S.-L.M.-T.O.D.		0.0169381%	
I.G.S. and C.S.-I.R.P		0.0130626%	
M.W.		0.0134057%	
O.L.		0.0009431%	
S.L.		0.0009890%	
	BETotal		CPTotal

6. "BETotal" is the sum of the BEClass for all tariff classes.

7. "CPTotal" is the sum of the CPClass for all tariff classes.

The factors as computed above are calculated to allow the recovery of Uncollectible Accounts Expense of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the Big Sandy Unit 1 Operation Rider revenues.

The annual Big Sandy Unit 1 Operation Rider factors shall be filed with the Commission ten (10) days before it is scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

RIDER N.C.C.R.
(NERC Compliance and Cybersecurity Rider)

APPLICABLE.

To Tariffs R.S., R.S.-L.M.-T.O.D., Experimental R.S.-T.O.D., R.S.-T.O.D. 2, S.G.S., S.G.S.-T.O.D., M.G.S., M.G.S.-T.O.D., L.G.S., L.G.S.-T.O.D., I.G.S., C.S.-I.R.P., M.W., O.L., and S.L.

RATES.

Tariff Class	¢/kWh	$/kW
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2	0.0000	–
S.G.S. and S.G.S.-T.O.D.	0.0000	--
M.G.S.	0.0000	0.00
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.	0.0000	–
L.G.S. and L.G.S.-T.O.D.	0.0000	0.00
L.G.S.-L.M.-T.O.D.	0.0000	0.00
I.G.S. and C.S.-I.R.P.	0.0000	0.00
M.W.	0.0000	--
O.L.	0.0000	--
S.L.	0.0000	--

The kWh adjustment factor as calculated above will be applied to all billing kilowatt-hours for those tariff classes listed above. The kW adjustment factor as calculated above will be applied to all on-peak and minimum billing demand kW for the MGS, LGS and IGS tariff classes.

The NERC Compliance and Cybersecurity Rider adjustment factors shall be modified annually to collect the Commission's approved annual level of Kentucky retail jurisdictional NERC Compliance and Cybersecurity expenses and any prior review period (over)/under recovery.

The NERC Compliance and Cybersecurity Rider adjustment factors shall be determined as follows:

For all tariff classes without demand billing:

$$\text{kWh Adjustment Factor} = \frac{\text{NCE x (BEClass /BETotal) + NCD x (CPClass /CPTotal)}}{\text{BEClass}}$$

$$\text{kW Adjustment Factor} = 0$$

For all tariff classes with demend billing:

$$\text{kWh Adjustment Factor} = \frac{\text{NCE x (BEClass /BETotal)}}{\text{BEClass}}$$

$$\text{kW Adjustment Factor} = \frac{\text{NCD x (CPClass /CPTotal)}}{\text{BDClass}}$$

Where:

1. "NCD" is the actual annual retail NERC Compliance and Cybersecurity demand-related costs, plus any prior review period (over)/under recovery.

2. "NCE" is the actual annual retail NERC Compliance and Cybersecurity energy-related costs, plus any prior review period (over)/under recovery.

3. "BE_{Class}" is the historic annual retail jurisdictional billing kWh for each tariff class for the current year.

4. "BD_{Class}" is the historic annual retail jurisdictional billing kW for each applicable tariff class for the current year.

5. "CP_{Class}" is the coincident peak demand for each tarlff class estimated as follows:

Tariff Class (1)	BEClass (2)	CP/kWh Ratio (3)	CPClass (4)=(2)x(3)
R.S., R.S.-L.M.-T.O.D., R.S.-T.O.D., and Experimental R.S.-T.O.D. 2		0.0236060%	
S.G.S. and S.G.S.-T.O.D.		0.0163937%	
M.G.S.		0.0177002%	
M.G.S. Recreational Lighting, M.G.S.-L.M.-T.O.D., and M.G.S.-T.O.D.		0.0177002%	
L.G.S. and L.G.S.-T.O.D.		0.0169381%	
L.G.S.-L.M.-T.O.D.		0.0169381%	
I.G.S. and C.S.-I.R.P.		0.0130626%	
M.W.		0.0134057%	
O.L.		0.0009431%	
S.L.		0.0009890%	
	BETotal		CPTotal

6. "BETotal" is the sum of the BEClass for all tariff classes.

7. "CPTotal" is the sum of the CPClass for all tariff classes.

The adjustment factor as computed above shall be further modified to allow the recovery of Uncollectible Accounts Expensa of 0.3% and the KPSC Maintenance Fee of 0.1952% and other similar revenue based taxes or assessments occasioned by the NERC Compliance and Cybersecurity Rider adjustment revenues.

The initial NERC Compliance and Cybersecurity Rider adjustment factors shall be filed with the Commission six (6) months before the initial rates are scheduled to go into effect and ten (10) days before any subsequent annual rate adjustments are scheduled to go into effect, along with all necessary supporting data to justify the amount of the adjustments, which shall include data and information as may be required by the Commission.

Copies of all documents required to be filed with the Commission shall be open and made available for public inspection at the office of the Public Service Commission pursuant to the provisions of KRS 61.870 to 61.884.

EFFECT OF PROPOSED CHANGE IN CUSTOMER RATES

If approved as filed, the Company's proposed changes to its rates and tariffs will result in a proposed annual increase in electric revenues for Kentucky Power of approximately 12.48%. Kentucky Power's proposal includes a proposed Transmission Adjustment which adjusts customers' charges based upon the wholesale cost of transmission. If that adjustment is not approved, and the remainder of the application is approved as filed, Kentucky Power's proposed annual increase in electric revenues will be approximately 12.51%.

The estimated annuel revenue increase per customer class, with and without the proposed Transmission Adjustment Tariff, is as follows:

		With Transmission Adjustment			Without Transmission Adjustment		
Customer Classification	Current Revenue	Proposed Revenue	Proposed Increase	Percent Change	Proposed Revenue	Proposed Increase	Percent Change
R.S.	$ 230,140,574	$ 267,061,060	$36,920,486	16.04%	$ 259,157,130	$29,016,556	12.61%
S.G.S.	$ 19,611,844	$ 21,651,296	$2,039,452	10.40%	$ 22,294,895	$2,683,051	13.68%
M.G.S.	$ 59,677,591	$ 64,645,805	$4,968,214	8.33%	$ 67,517,142	$7,839,551	13.14%
L.G.S.	$ 70,569,638	$ 78,000,563	$7,430,925	10.53%	$ 79,829,618	$9,259,980	13.12%
M.W.	$ 364,284	$ 395,083	$30,799	8.45%	$ 409,878	$45,594	12.52%
Q.P.*	$ 54,126,867	*$ 62,262,125*	*$8,135,258*	*15.03%*	*$ 63,610,634*	*$9,483,767*	*17.52%*
C.I.P. – T.O.D.*	$ 117,423,244	*$ 126,738,546*	*$9,315,302*	*7.93%*	*$ 128,052,015*	*$10,628,771*	*9.05%*
I.G.S.*	*$ 171,550,110*	$ 189,000,671	$17,450,561	10.17%	$ 191,662,649	$20,112,539	11.72%
C.S. – I.R.P.	No Customers	N/A	N/A	N/A	N/A	N/A	N/A
O.L.	$ 7,256,325	$ 8,191,296	$934,971	12.88%	$ 8,198,601	$942,276	12.99%
S.L.	$ 1,422,710	$ 1,609,696	$186,986	13.14%	$ 1,612,465	$189,755	13.34%
C.A.T.V. 2 User	$ 131,161	$ 131,161	$0	0.00%	$ 131,161	$0	0.00%
C.A.T.V. 3 User	$ 399,768	$ 399,768	$0	0.00%	$ 399,768	$0	0.00%
COGEN /SPP I	No Customers	N/A	N/A	N/A	N/A	N/A	N/A
COGEN /SPP II	No Customers	N/A	N/A	N/A	N/A	N/A	N/A

* – The italicized values above are illustrative only. In accordance with the Stipulation and Settlement Agreement approved by the Commission in Case No. 2012-00578, the Company is proposing to combine the current Tariff O.P. and Tariff C.I.P.-T.O.D. into a new Tariff I.G.S. The "proposed revenue," "proposed increase," and "percent change" values shown above for the O.P. and C.I.P.-T.O.D. clesses are illustrative and reflect the application of the proposed Tariff I.G.S. rates to customers currently taking service under Tariff Q.P. and Tariff C.I.P.-T.O.D. Because Kentucky Power is proposing to eliminate Tariff Q.P. and Tariff C.I.P.-T.O.D. classes, service will not be available under those classes if the Company's application is approved. In that case, customers currently receiving service under Tariff O.P. and Tariff C.I.P.-T.O.D will only be offered service under Tariff I.G.S. The "current revenue" value shown for Tariff I.G.S., which currently is not authorized, likewise is for illustrative purposes.

The average monthly bill for each customer class to which the proposed electric rates will apply will increase approximately as follows:

				With Transmission Adjustment			Without Transmission Adjustment		
Tariff Class	Average Customer Usage (kWh)	Average Customer Demand (kW)	Present Average Billing	Proposed Average Billing	Averege Billing Change	Averege Percent Change	Proposed Average Billing	Average Billing Change	Average Percent Change
R.S.	1,362	--	$138.67	$160.92	$22.25	16.04%	$156.16	$17.48	12.61%
S.G.S.	499	--	$68.60	$75.74	$7.13	10.40%	$77.99	$9.39	13.68%
M.G.S.	5,866	25	$681.53	$738.27	$56.74	8.33%	$771.06	$89.53	13.14%
L.G.S.	68,860	213	$6,870.10	$7,593.51	$723.42	10.53%	$7,771.57	$901.48	13.12%
M.W.	29,273	–	$2,759.73	$2,993.05	$233.32	8.45%	$3,105.14	$345.41	12.52%
O.P.*	825,567	2,063	$58,578.86	*$67,383.25*	*$8,804.39*	*15.03%*	*$68,842.68*	*$10,263.82*	*17.52%*
C.I.P. -T.O.D.*	15,578,803	26,395	$889,570.03	*$960,140.50*	*$70,570.47*	*7.93%*	*$970,091.02*	*$80,521.00*	*9.05%*
I.G.S.*	*2,669,721*	*5,105*	*$162,452.76*	$178,977.91	$16,525.15	10.17%	$181,498.72	$19,045.96	11.72%
C.S. – I.R.P.	No Customers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
O.L.	66	–	$12.79	$14.44	$1.65	12.88%	$14.45	$1.66	12.99%
S.L.	12,188	–	$2,117.13	$2,395.38	$278.25	13.14%	$2,399.50	$282.37	13.34%
C.A.T.V. 2 User	18,039 Attachments	N/A	$131,161	$0.00	$0.00	0.00%	$0.00	$0.00	0.00%
C.A.T.V. 3 User	91,260 Attachments	N/A	$399,768	$0.00	$0.00	0.00%	$0.00	$0.00	0.00%
COGEN /SSP I	No Customers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
COGEN /SPP II	No Customers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

* – The italicized values above are illustrative only. In accordance with the Stipulation and Settlement Agreement approved by the Commission In Case No. 2012-00578, the Company is proposing to combine the current Tariff Q.P. and Tariff C.I.P.-T.O.D. into a new Tariff I.G.S. The "proposed average billing," "average billing change," and " average percent change" values shown above for the Q.P. and C.I.P.-T.O.D. classes are illustrative and reflect the application of the proposed Tariff I.G.S. rates to customers currently taking service under Tariff Q.P. and Tariff C.I.P.-T.O.D. Because Kentucky Power is proposing to eliminate Tariff Q.P. and Tariff C.I.P.-T.O.D. classes, service will not be available under those classes if the Company's application is approved. In that case, customers currently receiving service under Tariff Q.P. and Tariff C.I.P.-T.O.D. will only be offered service under Tariff I.G.S. The "average customer usage," "average customer demand," and "present average billing" values shown for Tariff I.G.S., which currently is not authorized, likewise are for illustrative purposes and they represent the average of e single class combining Tariff O.P. and Tariff C.I.P.-T.O.D.

A copy of Kentucky Power's application, testimony, and any other filings in this case is available for public inspection at Kentucky Power's offices located at 101A Enterprise Drive, Frankfort, KY 40601 with a phone number of 502-696-7011; 12333 Kevin Avenue, Ashland, KY 41102 with a phone number of 606-929-1600; 1400 E. Main St. Hazard, KY 41701 with e phone number of 606-436-1322; and 3249 North Mayo Trail Pikeville, KY 41501 with a phone number of 606-437-3827, and the Company's website: www.kentuckypower.com.

The application, testimony and other related filings are also available for public inspection between the hours of 8:00 a.m. to 4:30 p.m., Monday through Friday, at the Commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky. The application, testimony and other related filings may also be found on the Commission's website: http://psc.ky.gov.

Written comments on Kentucky Power's application and the proposed rates may be submitted to the Commission by mail to: Public Service Commission, P. O. Box 615, Frankfort, Kentucky 40602-0615 or via the Commission's website: http://psc.ky.gov.

The Company is not proposing to modify other rates and charges not included in this Notice. The rates contained in this notice are the rates proposed by Kentucky Power. The Public Service Commission may order rates to be charged that differ from the proposed rates in this notice. Such action by the Commission may result in rates for customers other than the rates contained in this notice.

Any person may submit a timely written request for intervention in Case No. 2014-00396. The motion shall be submitted to the Public Service Commission, P. O. Box 615, Frankfort, Kentucky 40602-0615, and shall establish the grounds for the request, including the status and interest of the party. If the Commission does not receive a written request for intervention within thirty (30) days of the initial publication of this notice, the Commission may take final action on the application.

Filing Requirement
807 KAR 5:001 Section 16 (2)

Filing Requirement:

Utilities with gross annual revenues greater than $5,000,000 shall file with the Commission a written notice of intent to file a rate application at least thirty (30) days, but not more than sixty (60) days, prior to filing its application.

- ***a. The notice of intent shall state if the rate application will be supported by a historical test period or a fully forecasted test period.***
- ***b. Upon filing the notice of intent, an application may be made to the commission for permission to use an abbreviated form of newspaper notice of proposed rate increases provided the notice includes a coupon that may be used to obtain a copy from the applicant of the full schedule of increases or rate changes.***
- ***c. Upon filing the notice of intent with the commission, the applicant shall mail to the Attorney General's Office of Rate Intervention a copy of the notice of intent or send by electronic mail in a portable document format, to rateintervention@ag.ky.gov.***

Response:

Attached is a copy of the Company’s Notice of Intent to File for An Adjustment in Electric Rates as was filed with the Commission on November 14, 2014.

Kentucky Power has not made an application for permission to use an abbreviated form of the newspaper notice.

In conformity with 807 KAR 5:001, Section 16(2)(c), notice was also transmitted by electronic mail and U.S. Mail to the Attorney General’s Office of Rate Intervention.

RECEIVED
NOV 14 2014
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For: (1) A General Adjustment Of Its Rates For Electric Service; (2) An Order Approving Its 2014 Environmental Compliance Plan; (3) An Order Approving Its Tariffs And Riders; And (4) An Order Granting All Other Required Approvals And Relief	)))))))	Case No. 2014-00___

Notice Of Intent

Pursuant to 807 KAR 5:001, Section 16(2) and KRS 278.183(2) and all other applicable statutory provisions and regulations, Kentucky Power Company gives notice of its intent to file on or before December 29, 2014 an application seeking: (1) a general adjustment of its electric rates; (2) approval of its 2014 environmental compliance plan; (3) approval of its tariffs and riders, including its amended environmental cost recovery surcharge tariff to recover the costs associated with the environmental cost recovery plan; and (4) all other required approvals and relief. The Company's 2014 environmental compliance plan will supplement and modify Kentucky Power's existing environmental compliance plan.

The general adjustment of Kentucky Power Company's rates for electric service will be supported by the Company's historical test year for the twelve months ended September 30, 2014.

A copy of this notice of intent in a portable document format has been transmitted by electronic mail to the Attorney General's Office of Rate Intervention at rateintervention@ky.gov.[1] A copy of this notice of intent also has been mailed to the Attorney General's Office of Rate Intervention and to counsel for Kentucky Industrial Utility Customers, Inc.

Kentucky Power Company is contemporaneously filing a Request to Use Electronic Filing.

Respectfully submitted,

Mark R. Overstreet
R. Benjamin Crittenden
STITES & HARBISON PLLC
421 West Main Street
P. O. Box 634
Frankfort, Kentucky 40602-0634
Telephone: (502) 223-3477
moverstreet@stites.com
rcrittenden@stites.com

Kenneth J. Gish, Jr.
STITES & HARBISON PLLC
250 West Main Street, Suite 2300
Lexington, Kentucky 40507
Telephone: (859) 226-2300
kgish@stites.com

COUNSEL FOR KENTUCKY POWER COMPANY

[1] The address above is being used in lieu of the address in 807 KAR 5:001, Section 16(2) in light of the change in the address of the Attorney General's general mail box identified by Assistant Attorney General Hans on October 24, 2014.

CERTIFICATE OF SERVICE

I hereby certify that a copy of the foregoing was served upon the following by United States Mail, postage prepaid, this 14th day of November 2014.

Michael L. Kurtz
Jody Kyler Cohn
Boehm, Kurtz & Lowry
36 East Seventh Street, Suite 1510
Cincinnati, Ohio 45202
mkurtz@bkllawfirm.com
KBoehm@bkllawfirm.com
jkylercohn@bkllawfirm.com

Jennifer Black Hans
Angela Goad
Gregory T. Dutton
Lawrence W. Cook
Kentucky Attorney General's Office
1024 Capital Center Drive, Suite 200
Frankfort, Kentucky 40601-8204
jennifer.hans@ag.ky.gov
Angela.Goad@ag.ky.gov
larry.cook@ag.ky.gov
Gregory.Dutton@ag.ky.gov

Mark R. Overstreet

NOTICE OF ELECTION OF USE OF ELECTRONIC FILING PROCEDURES

(Complete All Shaded Areas and Check Applicable Boxes)

RECEIVED
NOV 14 2014
PUBLIC SERVICE COMMISSION

In accordance with 807 KAR 5:001, Section 8, Kentucky Power Company gives notice of its intent to file an application for General Adjustment of Rates, etc. with the Public Service Commission no later than December 29, 2014 and to use the electronic filing procedures set forth in that regulation.

Kentucky Power Company further states that:

		Yes	No
1.	It requests that the Public Service Commission assign a case number to the intended application and advise it of that number as soon as possible;	X	
2.	It or its authorized representatives have registered with the Public Service Commission and are authorized to make electronic filings with the Public Service Commission;	X	
3.	Neither it nor its authorized representatives have registered with the Public Service Commission for authorization to make electronic filings but will do so no later than seven days before the date of its filing of its application for rate adjustment;		n/a
4.	It or its authorized agents possess the facilities to receive electronic transmissions;	X	

5. The following persons are authorized to make filings on its behalf and to receive electronic service of Public Service Commission orders and any pleadings filed by any party or the Public Service Commission Staff:

Name	Electronic Mail Address
Mark R. Overstreet	moverstreet@stites.com
Kenneth J. Gish, Jr.	kgish@stites.com
Kentucky Power Company	kentucky_regulatory_services@aep.com

6. It and its authorized representatives listed above have read and understand the procedures for electronic filing set forth in 807 KAR 5:001 and will fully comply with those procedures unless the Public Service Commission directs otherwise. Yes: X No: ☐

Signed

Name: Mark R. Overstreet

Title: Counsel for Kentucky Power Company

Address: P.O. Box 634

Frankfort, Kentucky 40602-0634

Telephone Number: (502) 223-3477

Filing Requirement
807 KAR 5:001 Section 16 (4)(a)

Filing Requirement:

Each application supported by a historical test period shall include the following information or a statement explaining why the required information does not exist and is not applicable to the utility's application:

> ***A complete description and quantified explanation for all proposed adjustments with proper support for proposed changes in price or activity levels, if applicable, and other factors that may affect the adjustment;***

Response:

The complete descriptions and quantified explanations for all proposed adjustments, with proper support for any proposed changes in price or activity levels, and any other factors, are provided in Section III and Section V of Application.

Filing Requirement
807 KAR 5:001 Section 16 (4)(b)

Filing Requirement:

If the utility has gross annual revenues greater than $5,000,000, the written testimony of each witness the utility proposes to use to support its application;

Response:

Please refer to the testimony and exhibits of the following persons:

Gregory G. Pauley
William Avera/Adrien McKenzie
Jeffrey B. Bartsch
Andrew R. Carlin
David A. Davis
Amy J. Elliott
Jeffrey LaFleur
Shannon R. Listebarger
Hugh E. McCoy
John M. McManus
Everett G. Phillips
John A. Rogness
Marc D. Reitter
Jason M. Stegall
H. Kevin Stogran
Alex E. Vaughan
Ranie K. Wohnhas
Jason M. Yoder

Filing Requirement
807 KAR 5:001 Section 16 (4)(c)

Filing Requirement:

If the utility has gross annual revenues less than $5,000,000 the written testimony of each witness the utility proposes to use to support its application or a statement that the utility does not plan to submit written testimony;

Response:

Not Applicable.

Filing Requirement
807 KAR 5:001 Section 16 (4)(d)

Filing Requirement:

A statement estimating the effect that each new rate will have upon the revenues of the utility including, at minimum, the total amount of revenues resulting from the increase or decrease and the percentage of the increase or decrease;

Response:

The required statement is presented in Section III of this application in the testimony of Company Witness Wohnhas at page 5.

Filing Requirement
807 KAR 5:001 Section 16 (4)(e)

Filing Requirement:

If the utility provides electric, gas, water, or sewer service, the effect upon the average bill for each customer classification to which the proposed rate change will apply;

Response:

The chart below shows the effect upon the average bill for each customer classification to which the proposed rate change will apply.

				With Transmission Adjustment			Without Transmission Adjustment		
Tariff Class	Average Customer Usage (kWh)	Average Customer Demand (kW)	Present Average Billing	Proposed Average Billing	Average Billing Change	Average Percent Change	Proposed Average Billing	Average Billing Change	Average Percent Change
R.S.	1,362		$138.67	$160.92	$22.25	16.04%	$156.16	$17.48	12.61%
S.G.S.	499		$68.60	$75.74	$7.13	10.40%	$77.99	$9.39	13.68%
M.G.S.	5,866	25	$681.53	$738.27	$56.74	8.33%	$771.06	$89.53	13.14%
L.G.S.	68,860	213	$6,870.10	$7,593.51	$723.42	10.53%	$7,771.57	$901.48	13.12%
M.W.	29,273		$2,759.73	$2,993.05	$233.32	8.45%	$3,105.14	$345.41	12.52%
Q.P.*	825,567	2,063	$58,578.86	*$67,383.25*	*$8,804.39*	*15.03%*	*$68,842.68*	*$10,263.82*	*17.52%*
C.I.P.-T.O.D.*	15,578,803	26,395	$889,570.03	*$960,140.50*	*$70,570.47*	*7.93%*	*$970,091.02*	*$80,521.00*	*9.05%*
I.G.S.*	*2,669,721*	*5,105*	*$162,452.76*	$178,977.91	$16,525.15	10.17%	$181,498.72	$19,045.96	11.72%
C.S. – I.R.P.	No Customers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
O.L.	66		$12.79	$14.44	$1.65	12.88%	$14.45	$1.66	12.99%
S.L.	12,188		$2,117.13	$2,395.38	$278.25	13.14%	$2,399.50	$282.37	13.34%
C.A.T.V. 2 User	18,039 Attachments	N/A	$131,161	$0.00	$0.00	0.00%	$0.00	$0.00	0.00%
C.A.T.V. 3 User	91,260 Attachments	N/A	$399,768	$0.00	$0.00	0.00%	$0.00	$0.00	0.00%
COGEN/SSP I	No Customers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A
COGEN/SPP II	No Customers	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

*In accordance with the Stipulation and Settlement Agreement approved by the Commission in Case No. 2012-00578, the Company is proposing to combine the current Tariff Q.P. and Tariff C.I.P.-T.O.D. into a new Tariff I.G.S. The “proposed average billing,” “average billing change,” and “ average percent change” values shown above for the Q.P. and C.I.P.-T.O.D. classes are illustrative and reflect the application of the proposed Tariff I.G.S. rates to customers currently taking service under Tariff Q.P. and Tariff C.I.P.-T.O.D. Because Kentucky Power is proposing to eliminate Tariff Q.P. and Tariff C.I.P.-T.O.D. classes, service will not be available under those classes if the Company’s application is approved. In that case, customers currently receiving service under Tariff Q.P. and Tariff C.I.P.-T.O.D. will only be offered service under Tariff I.G.S. The “average customer usage,” “average customer demand,” and “present average billing” values shown for Tariff I.G.S., which currently is not authorized, likewise are for illustrative purposes and the represent the average of a single class combining Tariff Q.P. and Tariff C.I.P.-T.O.D.

Filing Requirement
807 KAR 5:001 Section 16 (4)(f)

Filing Requirement:

If the utility is an incumbent local exchange company, the effect upon the average bill for each customer class for the proposed rate change in basic local service;

Response:

Not Applicable.

Filing Requirement
807 KAR 5:001 Section 16 (4)(g)

Filing Requirement:

A detailed analysis of customers' bills whereby revenues from the present and proposed rates can be readily determined for each customer class;

Response:

Please see the attached document for a detailed billing analysis.

The following chart shows revenues from the present and proposed rates for each customer class.

		With Transmission Adjustment			Without Transmission Adjustment		
Customer Classification	Current Revenue	Proposed Revenue	Proposed Increase	Percent Change	Proposed Revenue	Proposed Increase	Percent Change
R.S.	$ 230,140,574	$ 267,061,060	$36,920,486	16.04%	$ 259,157,130	$29,016,556	12.61%
S.G.S.	$ 19,611,844	$ 21,651,296	$2,039,452	10.40%	$ 22,294,895	$2,683,051	13.68%
M.G.S.	$ 59,677,591	$ 64,645,805	$4,968,214	8.33%	$ 67,517,142	$7,839,551	13.14%
L.G.S.	$ 70,569,638	$ 78,000,563	$7,430,925	10.53%	$ 79,829,618	$9,259,980	13.12%
M.W.	$ 364,284	$ 395,083	$30,799	8.45%	$ 409,878	$45,594	12.52%
Q.P.*	$ 54,126,867	*$ 62,262,125*	*$8,135,258*	*15.03%*	*$ 63,610,634*	*$9,483,767*	*17.52%*
C.I.P. – T.O.D.*	$ 117,423,244	*$ 126,738,546*	*$9,315,302*	*7.93%*	*$ 128,052,015*	*$10,628,771*	*9.05%*
I.G.S.*	*$ 171,550,110*	$ 189,000,671	$17,450,561	10.17%	$ 191,662,649	$20,112,539	11.72%
C.S. – I.R.P.	No Customers	N/A	N/A	N/A	N/A	N/A	N/A
O.L.	$ 7,256,325	$ 8,191,296	$934,971	12.88%	$ 8,198,601	$942,276	12.99%
S.L.	$ 1,422,710	$ 1,609,696	$186,986	13.14%	$ 1,612,465	$189,755	13.34%
C.A.T.V. 2 User	$ 131,161	$ 131,161	$0	0.00%	$ 131,161	$0	0.00%
C.A.T.V. 3 User	$ 399,768	$ 399,768	$0	0.00%	$ 399,768	$0	0.00%
COGEN/SPP I	No Customers	N/A	N/A	N/A	N/A	N/A	N/A
COGEN/SPP II	No Customers	N/A	N/A	N/A	N/A	N/A	N/A

*In accordance with the Stipulation and Settlement Agreement approved by the Commission in Case No. 2012-00578, the Company is proposing to combine the current Tariff Q.P. and Tariff C.I.P.-T.O.D. into a new Tariff I.G.S. The “proposed average billing,” “average billing change,” and “ average percent change” values shown above for the Q.P. and C.I.P.-T.O.D. classes are illustrative and reflect the application of the proposed Tariff I.G.S. rates to customers currently taking service under Tariff Q.P. and Tariff C.I.P.-T.O.D. Because Kentucky Power is proposing to eliminate Tariff Q.P. and Tariff C.I.P.-T.O.D. classes, service will not be available under those classes if the Company’s application is approved. In that case, customers currently receiving service under Tariff Q.P. and Tariff C.I.P.-T.O.D. will only be offered service under Tariff I.G.S. The “average customer usage,” “average customer demand,” and “present average billing” values shown for Tariff I.G.S., which currently is not authorized, likewise are for illustrative purposes and the represent the average of a single class combining Tariff Q.P. and Tariff C.I.P.-T.O.D.

KENTUCKY POWER BILLING ANALYSIS
TEST YEAR ENDED SEPTEMBER 30, 2014
REVENUE SUMMARY SHEET

Tariff	Total Per Books Revenue	Revenue Without Green Power	Revenue Without System Sales	Revenue Without Capacity Charge	Revenue Without Env. Surcharge	Revenue With Annualized Fuel	Year End Migration Revenue	Weather Normalization Revenue	Year End Customer Revenue
RS Total	$234,174,671	$234,174,671	$233,237,561	$230,972,116	$232,147,083	$231,456,855	$231,803,910	$225,886,315	$224,199,303
RSLMTOD Total	$398,123	$398,123	$396,348	$382,094	$393,973	$393,847	$396,225	$384,689	$380,811
RS TOD Total	$4,356	$4,356	$4,337	$4,292	$4,315	$4,289	$4,289	$4,289	$4,289
Residential Total	$234,577,150	$234,577,150	$233,638,245	$231,368,501	$232,545,971	$231,854,991	$232,204,424	$226,275,293	$224,584,403
OL Total	$7,991,785	$7,991,785	$7,972,485	$7,931,109	$7,973,685	$7,956,803	$7,956,803	$7,956,803	$7,018,556
SGS Metered Total	$18,612,752	$18,612,752	$18,559,652	$18,423,858	$18,516,621	$18,425,841	$18,239,353	$18,239,353	$18,312,337
SGSLMTOD (225)	$535	$535	$534	$532	$534	$528	$528	$528	$528
SGS NM Total	$636,368	$636,368	$634,927	$631,084	$634,348	$629,848	$629,848	$629,848	$633,460
SGS TOD	$54,712	$54,712	$54,576	$54,217	$54,500	$54,076	$54,076	$54,076	$53,432
SGS Total	$19,304,368	$19,304,368	$19,249,689	$19,109,690	$19,206,003	$19,110,292	$18,923,805	$18,923,805	$18,999,757
MGS RL (214)	$176,304	$176,304	$175,717	$174,143	$175,037	$173,117	$164,225	$164,225	$167,123
MGS Sec	$56,778,689	$56,778,689	$56,601,476	$56,121,038	$56,397,272	$55,932,536	$55,909,224	$55,909,224	$56,124,436
MGSLMTOD (223)	$107,868	$107,868	$107,442	$106,413	$106,893	$107,154	$107,154	$107,154	$106,575
MGSTOD (229)	$383,289	$383,289	$381,888	$378,177	$380,026	$377,222	$378,348	$378,348	$381,274
MGS Pri Total	$841,956	$841,956	$839,254	$831,672	$835,523	$828,131	$1,035,270	$1,035,270	$995,527
MGS Sub (236)	$174,768	$174,768	$174,336	$172,869	$173,728	$172,405	$122,264	$122,264	$118,250
MGS Total	$58,462,873	$58,462,873	$58,280,113	$57,784,312	$58,068,479	$57,590,564	$57,716,485	$57,716,485	$57,893,185
LGS Sec Total	$56,129,059	$56,129,059	$55,930,144	$55,396,857	$55,680,139	$55,078,752	$55,324,875	$55,324,875	$55,924,423
LGSLMTOD (251)	$196,457	$196,457	$195,692	$193,791	$194,869	$193,121	$193,121	$193,121	$193,129
LGS Pri Total	$8,598,357	$8,598,357	$8,563,057	$8,473,361	$8,518,690	$8,439,085	$8,186,301	$8,186,301	$9,997,622
LGS Sub (248)	$2,377,009	$2,377,009	$2,364,772	$2,333,466	$2,345,440	$2,311,881	$2,646,442	$2,646,442	$2,433,638
LGS Tran (250)	$164,354	$164,354	$163,125	$161,108	$162,116	$164,873	$67,113	$67,113	$67,112
LGS Total	$67,465,236	$67,465,236	$67,216,790	$66,558,583	$66,901,254	$66,187,712	$66,417,851	$66,417,851	$68,615,924
QP Sec (356)	$1,898,831	$1,898,831	$1,893,713	$1,873,315	$1,880,836	$1,852,936	$1,972,823	$1,972,823	$1,893,876
QP Pri (357,358)	$25,231,062	$25,231,062	$25,115,669	$24,794,647	$24,920,074	$24,503,008	$24,295,105	$24,295,105	$24,295,071
QP Sub (359)	$22,926,271	$22,926,271	$22,804,383	$22,481,927	$22,596,237	$22,234,697	$22,834,308	$22,834,308	$22,688,792
QP Tran (360)	$2,543,285	$2,543,285	$2,539,322	$2,504,536	$2,508,296	$2,410,777	$3,616,522	$3,616,522	$3,945,188
CIP Sub (371)	$102,505,258	$102,505,258	$101,851,584	$100,675,554	$101,169,944	$99,122,705	$98,063,673	$98,063,673	$99,137,776
CIP Tran (372)	$19,189,780	$19,189,780	$19,053,620	$18,826,712	$18,943,564	$18,593,466	$17,507,511	$17,507,511	$16,160,781
QP/CIP Total	$174,294,487	$174,294,487	$173,258,291	$171,156,690	$172,018,950	$168,717,588	$168,289,943	$168,289,943	$168,121,484
SL (528)	$1,437,808	$1,437,808	$1,434,027	$1,425,746	$1,432,732	$1,428,283	$1,428,283	$1,428,283	$1,375,748
MW (540)	$361,825	$361,825	$360,423	$356,675	$358,545	$354,484	$354,484	$354,484	$354,486
Total	$563,895,531	$563,895,531	$561,410,063	$555,691,306	$558,505,619	$553,200,718	$553,292,078	$547,362,947	$546,963,544

Tariff	Asset Transfer Rider Adjustment	Asset Transfer Rider Over/Under	Current Revenues	Proposed Revenue Increase	Proposed Revenue	Verification Difference	Rate Design Proposed Revenue	Proposed Transmission Adjustment	Proposed Revenue w/ Transmission Adjustment
RS Total	$4,075,208	$1,471,306	$229,745,817				$227,243,078	$7,890,598	$235,133,676
RSLMTOD Total	$7,014	$2,532	$390,357				$379,586	$13,180	$392,766
RS TOD Total	$75	$27	$4,391				$4,388	$152	$4,540
Residential Total	$4,082,297	$1,473,865	$230,140,566	($2,501,105)	$227,639,469	$12,417	$227,627,052	$7,903,930	$235,530,982
OL Total	$174,693	$63,071	$7,256,320	($86,520)	$7,169,805	$21	$7,169,784	($7,305)	$7,162,479
SGS Metered Total	$433,239	$156,416	$18,901,993				$18,712,338	($618,501)	$18,093,837
SGSLMTOD (225)	$13	$5	$547				$540	($18)	$522
SGS NM Total	$15,190	$5,484	$654,134				$705,732	($23,327)	$682,405
SGS TOD	$1,279	$482	$55,173				$53,036	($1,753)	$51,283
SGS Total	$449,721	$162,367	$19,611,846	($139,867)	$19,471,977	$332	$19,471,645	($643,599)	$18,828,046
MGS RL (214)	$3,533	$1,275	$171,931				$186,560	($9,037)	$177,523
MGS Sec	$1,273,061	$459,623	$57,857,120				$57,391,534	($2,779,954)	$54,611,580
MGSLMTOD (223)	$2,486	$898	$109,959				$111,230	($5,388)	$105,842
MGSTOD (229)	$8,399	$3,032	$392,706				$402,392	($19,491)	$382,901
MGS Pri Total	$21,055	$7,602	$1,024,184				$1,043,983	($50,569)	$993,414
MGS Sub (236)	$2,529	$913	$121,692				$142,417	($6,898)	$135,519
MGS Total	$1,311,063	$473,343	$59,677,592	($399,476)	$59,278,115	($1)	$59,278,116	($2,871,337)	$56,406,779
LGS Sec Total	$1,186,145	$428,243	$57,538,811				$56,955,267	($1,486,851)	$55,468,416
LGSLMTOD (251)	$4,022	$1,452	$198,602				$194,114	($5,067)	$189,047
LGS Pri Total	$203,960	$73,637	$10,275,219				$10,415,927	($271,914)	$10,144,013
LGS Sub (248)	$41,508	$14,986	$2,490,132				$2,422,548	($63,242)	$2,359,306
LGS Tran (250)	($168)	($61)	$66,883				$75,878	($1,981)	$73,897
LGS Total	$1,435,466	$518,257	$70,569,647	($505,892)	$70,063,746	$12	$70,063,734	($1,829,055)	$68,234,679
QP Sec (356)	$37,744	$13,627	$1,945,247				$2,010,539	($48,308)	$1,962,231
QP Pri (357,358)	$433,913	$156,659	$24,885,642				$26,292,641	($631,739)	$25,660,902
QP Sub (359)	$402,343	$145,261	$23,236,396				$23,650,663	($568,260)	$23,082,403
QP Tran (360)	$84,049	$30,345	$4,059,582				$4,170,364	($100,202)	$4,070,162
CIP Sub (371)	$1,379,302	$497,980	$101,015,058				$97,784,131	($1,122,941)	$96,661,190
CIP Tran (372)	$181,775	$65,628	$16,408,184				$16,590,945	($190,528)	$16,400,417
QP/CIP Total	$2,519,125	$909,500	$171,550,109	($1,050,770)	$170,499,341	$58	$170,499,283	($2,661,978)	$167,837,305
SL (528)	$34,504	$12,457	$1,422,709	($10,348)	$1,412,362	$4	$1,412,358	($2,769)	$1,409,589
MW (540)	$7,199	$2,599	$364,284	($2,332)	$361,952	$13	$381,939	($14,795)	$347,144
Total	$10,014,069	$3,615,459	$560,593,072	($4,696,310)	$555,896,767	$12,856	$555,883,911	($126,908)	$555,757,003

KENTUCKY POWER BILLING ANALYSIS
TEST YEAR ENDED SEPTEMBER 30, 2014
PROFORMA SUMMARY

Tariff	Total Current Revenue	Total Proposed Revenue	Difference	% Difference
RS Total	$229,745,818	$266,609,018	$36,863,200	16.05%
RSLMTOD Total	$390,357	$446,884	$56,526	14.48%
RSTOD Total	$4,391	$5,159	$768	17.48%
OL Total	$7,256,320	$8,191,296	$934,976	12.88%
SGS Metered Total	$18,901,993	$20,803,658	$1,901,665	10.06%
SGSLMTOD (225)	$547	$602	$55	10.14%
SGSEXPTOD (227)	$55,173	$59,033	$3,861	7.00%
SGS NM Total	$654,134	$788,003	$133,869	20.47%
MGS RL (214)	$171,931	$203,649	$31,718	18.45%
MGS Sec Total	$57,857,120	$62,588,972	$4,731,851	8.18%
MGSLMTOD (223)	$109,959	$121,222	$11,263	10.24%
MGSTOD (229)	$392,706	$438,274	$45,568	11.60%
MGS Pri Total	$1,024,184	$1,138,577	$114,394	11.17%
MGS Sub (236)	$121,692	$155,111	$33,419	27.46%
LGS Sec Total	$57,538,811	$63,406,936	$5,868,125	10.20%
LGSLMTOD (251)	$198,602	$216,086	$17,484	8.80%
LGS Pri Total	$10,275,219	$11,605,926	$1,330,708	12.95%
LGS Sub (248)	$2,490,132	$2,685,280	$195,147	7.84%
LGS Tran (250)	$66,883	$86,305	$19,422	29.04%
QP Sec (356)	$1,945,247	$2,237,033	$291,785	15.00%
QP Pri (358)	$24,885,642	$29,169,854	$4,284,212	17.22%
QP Sub (359)	$23,236,396	$26,256,009	$3,019,612	13.00%
QP Tran (360)	$4,059,582	$4,599,230	$539,648	13.29%
CIP Sub (371)	$101,015,058	$108,310,827	$7,295,770	7.22%
CIP Tran (372)	$16,408,184	$18,427,718	$2,019,535	12.31%
SL (528)	$1,422,709	$1,609,696	$186,987	13.14%
MW (540)	$364,284	$395,083	$30,799	8.45%
Total	**$560,593,073**	**$630,555,440**	**$69,962,367**	**12.48%**

KENTUCKY POWER BILLING ANALYSIS
TEST YEAR ENDED SEPTEMBER 30, 2014
PROFORMA SUMMARY WITH PROPOSED RIDERS

	Current Base*	ATR	Current Total	Proposed Base**	Base Increase	% Increase	Economic Development Rider	Big Sandy Retirement Rider	Big Sandy Unit 1 Operations Ridar	Environmental Surcharge	Proposed Total	Revenue Before % Surcharges	C&I Fuel Revenue	Non-Fuel C&I Revenue Before % Surcharges
RS	$211,840,094	$17,905,723	$229,745,818	$235,133,676	$23,293,582	11.00%	$248,731	$9,241,017	$7,444,396	$14,541,197	$266,609,018	$242,826,803		
RS LM TOD	$359,538	$30,819	$390,357	$392,766	$33,228	9.24%	$310	$15,490	$13,945	$24,374	$446,884	$407,021		
RS TOD	$4,060	$331	$4,391	$4,540	$480	11.82%	$5	$179	$153	$281	$5,159	$4,699		
Total Residential	$212,203,692	$17,936,874	$230,140,567	$235,530,982	$23,327,290	10.99%	$249,046	$9,256,685	$7,458,494	$14,565,852	$267,061,060	$243,238,523		
OL Total	$6,488,749	$767,571	$7,256,320	$7,162,479	$673,730	10.38%	$0	$378,267	$55,332	$595,219	$8,191,296	$7,217,811	$1,145,822	$6,071,989
SGS Metered	$16,998,418	$1,903,575	$18,901,993	$18,093,837	$1,095,419	6.44%	$40,735	$891,051	$375,927	$1,402,108	$20,803,658	$18,510,498	$4,207,218	$14,303,281
SGS LM TOD	$487	$59	$547	$522	$34	7.02%	$2	$27	$8	$43	$602	$532	$92	$440
SGS EXP TOD	$49,553	$5,620	$55,173	$51,283	$1,730	3.49%	$137	$2,572	$994	$4,048	$59,033	$52,413	$11,121	$41,292
SGS NM	$587,394	$66,740	$654,134	$682,405	$95,011	16.18%	$2,639	$35,796	$10,837	$56,327	$788,003	$695,880	$121,278	$574,603
Total SGS	$17,635,851	$1,975,995	$19,611,846	$18,828,046	$1,192,195	6.76%	$43,513	$929,447	$387,765	$1,462,525	$21,651,296	$19,259,324	$4,339,709	$14,919,615
MGS RL	$156,410	$15,521	$171,931	$177,523	$21,113	13.50%	$139	$8,379	$4,424	$13,185	$203,649	$182,085	$47,584	$134,501
MGS SEC	$52,263,520	$5,593,600	$57,857,120	$54,611,580	$2,348,059	4.49%	$12,603	$2,548,418	$1,406,327	$4,010,044	$62,588,972	$56,030,510	$15,122,962	$40,907,548
MGS LM TOD	$99,035	$10,924	$109,959	$105,842	$6,807	6.87%	$83	$4,784	$2,986	$7,528	$121,222	$108,910	$32,116	$76,794
MGS TOD	$355,801	$36,904	$392,706	$382,901	$27,100	7.62%	$137	$17,211	$10,942	$27,083	$438,274	$393,980	$117,703	$276,278
MGS PRI	$931,672	$92,512	$1,024,184	$993,414	$61,743	6.63%	$151	$45,837	$27,050	$72,126	$1,138,577	$1,020,615	$284,841	$735,775
MGS SUB	$110,580	$11,112	$121,692	$135,519	$24,939	22.55%	$18	$6,681	$2,380	$10,512	$155,111	$137,918	$30,678	$107,240
MGS	$53,917,018	$5,760,574	$59,677,592	$56,406,779	$2,489,761	4.62%	$13,130	$2,631,309	$1,454,109	$4,140,478	$64,645,805	$57,874,018	$15,635,882	$42,238,136
LGS SEC	$52,327,106	$5,211,705	$57,538,811	$55,468,416	$3,141,309	6.00%	$1,346	$2,490,957	$1,526,589	$3,919,628	$63,406,936	$56,996,350	$17,011,161	$39,985,189
LGS LM TOD	$180,932	$17,670	$198,602	$189,047	$8,115	4.49%	$16	$8,398	$5,409	$13,215	$216,086	$194,473	$59,663	$134,810
LGS PRI	$9,379,057	$896,161	$10,275,219	$10,144,013	$764,956	8.16%	$140	$439,762	$330,026	$691,985	$11,605,926	$10,474,180	$3,415,058	$7,059,122
LGS SUB	$2,307,753	$182,379	$2,490,132	$2,359,306	$51,553	2.23%	$36	$89,052	$96,760	$140,127	$2,685,280	$2,456,101	$1,026,633	$1,429,469
LGS TRAN	$67,621	($738)	$66,883	$73,897	$6,276	9.28%	$2	$3,535	$3,309	$5,562	$86,305	$77,209	$20,469	$56,739
LGS	$64,262,470	$6,307,177	$70,569,647	$68,234,679	$3,972,209	6.18%	$1,541	$3,031,704	$1,962,094	$4,770,516	$78,000,533	$70,198,313	$21,532,984	$48,665,329
QP SEC	$1,779,406	$165,841	$1,945,247	$1,962,231	$182,825	10.27%	$11	$83,460	$60,002	$131,329	$2,237,033	$2,022,244	$682,525	$1,339,719
QP PRI	$22,979,109	$1,906,533	$24,885,642	$25,660,902	$2,681,793	11.67%	$72	$1,024,856	$871,368	$1,612,655	$29,169,854	$26,532,343	$10,081,212	$16,451,130
QP SUB	$21,468,574	$1,767,822	$23,236,396	$23,082,403	$1,613,828	7.52%	$46	$850,043	$985,937	$1,337,580	$26,256,009	$24,068,386	$10,423,371	$13,645,014
QP TRAN	$3,690,286	$369,296	$4,059,582	$4,070,162	$379,876	10.29%	$9	$138,616	$172,326	$218,118	$4,599,230	$4,242,496	$2,017,416	$2,225,080
QP	$49,917,375	$4,209,493	$54,126,868	$54,775,698	$4,858,323	9.73%	$138	$2,096,976	$2,089,633	$3,299,681	$62,262,125	$56,865,468	$23,204,524	$33,660,944
CIP TOD SUB	$94,954,657	$6,060,400	$101,015,058	$96,661,190	$1,706,533	1.80%	$16	$2,932,030	$4,103,916	$4,613,675	$108,310,827	$100,765,122	$53,699,773	$47,065,349
CIP TOD TRAN	$15,609,499	$798,685	$16,408,184	$16,400,417	$790,918	5.07%	$4	$511,568	$710,755	$804,975	$18,427,718	$17,111,176	$8,899,411	$8,211,764
CIP TOD	$110,564,156	$6,859,085	$117,423,241	$113,061,607	$2,497,451	2.26%	$20	$3,443,598	$4,814,671	$5,418,650	$126,738,546	$117,876,298	$62,599,184	$55,277,113
SL	$1,271,106	$151,602	$1,422,709	$1,409,589	$138,483	10.89%	$101	$73,038	$12,039	$114,928	$1,609,696	$1,421,730	$249,315	$1,172,414
MW	$332,654	$31,629	$364,284	$347,144	$14,489	4.36%	$20	$14,896	$9,583	$23,440	$395,083	$356,746	$117,626	$239,120
Total	$516,593,073	$44,000,000	$560,593,073	$555,757,003	$39,163,930	7.58%	$307,507	$21,855,921	$18,243,719	$34,391,290	$630,555,440	$574,308,229	$128,825,046	$202,244,660
Res												$243,238,523		
C&I												$331,069,707	$128,825,046	$202,244,660

* Current Base includes both Base Revenues and Current Annualized FAC
** Proposed Base includes Base Revenues, ATR and FAC

This sheet contains data from the rate design process.
It is set up to identify revenue differences between Class Cost of Service Study and the application of new rates to the test year billing determinants

Tariff Sheet	Calculated Base Revs	Rate Design Difference	Subtotal	CCOS Revenue	Variance
RS	$235,133,676				
RS LM TOD	$392,766				
RS TOD	$4,540				
Total Residential	$235,530,982	$12,418	$235,543,400	$235,543,399	$1
OL Total	$7,162,479	$3	$7,162,482	$7,162,499	-$17
SGS Metered	$18,093,837				
SGS LM TOD	$522				
SGS EXP TOD	$51,283				
SGS NM	$682,405				
Total SGS	$18,828,046	$331	$18,828,377	$18,828,378	-$1
MGS RL	$177,523				
MGS SEC	$54,611,580				
MGS LM TOD	$105,842				
MGS TOD	$382,901				
MGS PRI	$993,414				
MGS SUB	$135,519				
MGS	$56,406,779	$0	$56,406,779	$56,406,778	$1
LGS SEC	$55,468,416				
LGS LM TOD	$189,047				
LGS PRI	$10,144,013				
LGS SUB	$2,359,306				
LGS TRAN	$73,897				
LGS	$68,234,679	$11	$68,234,690	$68,234,691	-$1
QP SEC	$1,962,231				
QP PRI	$25,660,902				
QP SUB	$23,082,403				
QP TRAN	$4,070,162				
CIP TOD SUB	$96,661,190				
CIP TOD TRAN	$16,400,417				
QP/CIP TOD	$167,837,305	$55	$167,837,360	$167,837,363	-$3
SL	$1,409,589	$4	$1,409,593	$1,409,592	$1
MW	$347,144	$13	$347,157	$347,157	$0
Total	$555,757,003	$12,835	$555,769,838	$555,769,857	-$19

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

RESIDENTIAL SERVICE (011, 012, 013, 014, 015, 017, 022, 054)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
All kWh	2,255,616,379	$0.08590	$193,757,447	2,255,616,379	$0.09035	$203,794,940
Storage Water Heating	261,119	$0.04940	$12,899	261,119	$0.05216	$13,620
Metered kWh	2,255,877,500			2,255,877,500		
Customer Charge	1,658,209	$8.00	$13,265,673	1,658,209	$16.00	$26,531,344
HEAP Charge	1,658,209	$0.15	$248,731	1,658,209	$0.15	$248,731
Number of Customers	1,657,500			1,657,500		
Employee Discount			($49,177)			($59,480)
Fuel		$0.0020411	$4,604,521		$0.0020411	$4,604,521
Asset Transfer Rider			$17,905,723			
Economic Development Rider				1,658,209	$0.15	$248,731
Big Sandy 1 Operations Rider				2,255,877,500	$0.00330	$7,444,396
Big Sandy Retirement Rider				$242,826,803	3.8056%	$9,241,017
Environmental Surcharge			$0	$242,826,803	5.9883%	$14,541,197
Total			$229,745,818			$266,609,018

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	)	
A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

SECTION II

FILING REQUIREMENTS

VOLUME 2 OF 5

December 23, 2014

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

RESIDENTIAL LOAD MANAGEMENT TIME-OF-DAY SERVICE (028, 030, 032, 034)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	1,479,989	$0.13227	$195,758	1,479,989	$0.13879	$205,408
Off-peak kWh	2,745,767	$0.04940	$135,641	2,745,767	$0.05216	$143,219
Metered kWh	4,225,756			4,225,756		
C&LM Credit	0	($0.00745)	$0	-	($0.00745)	$0
Customer Charge *	1,957	$10.55	$20,645	1,957	$18.70	$36,596
Separate Meter Charge *	107	$3.00	$321	107	$3.85	$412
HEAP Charge	2,064	$0.15	$310	2,064	$0.15	$310
Number of Customers	2,064			2,064		
Employee Discount			($1,762)			($1,804)
Fuel		$0.0020411	$8,625		$0.0020411	$8,625
Asset Transfer Rider			$30,819			
Economic Development Rider			$0	2,064	$0.15	$310
Big Sandy 1 Operations Rider			$0	4,225,756	$0.00330	$13,945
Big Sandy Retirement Rider			$0	$407,021	3.8056%	$15,490
Environmental Surcharge			$0	$407,021	5.9883%	$24,374
Total			$390,357			$446,884

* Includes current HEAP Charge

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

RESIDENTIAL TIME-OF-DAY SERVICE (036)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	15,485	$0.13227	$2,048	15,485	$0.13879	$2,149
Off-peak kWh	31,006	$0.04940	$1,532	31,006	$0.05216	$1,617
Metered kWh	46,491			46,491		
Customer Charge	36	$10.55	$380	36	$18.70	$673
HEAP Charge	36	$0.15	$5	36	$0.15	$5
Number of Customers	36			36		
Employee Discount			$0			$0
Fuel		$0.0020411	$95		$0.0020411	$95
Asset Transfer Rider			$331			
Economic Development Rider			$0	36	$0.15	$5
Big Sandy 1 Operations Rider			$0	46,491	$0.00330	$153
Big Sandy Retirement Rider			$0	$4,699	3.8056%	$179
Environmental Surcharge			$0	$4,699	5.9883%	$281
Total			$4,391			$5,159

* Includes current HEAP Charge

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

SMALL GENERAL SERVICE (211, 212)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 500 kWh	62,183,999	$0.13160	$8,183,414	62,183,999	$0.11500	$7,151,160
Over 500 kWh	76,024,369	$0.07116	$5,409,894	76,024,369	$0.07057	$5,365,040
Metered kWh	138,208,368			138,208,368		
Customer Charge	271,566	$11.50	$3,123,009	271,566	$19.50	$5,295,537
Number of Customers	271,464			271,464		
Fuel		$0.0020411	$282,100		$0.0020411	$282,100
Asset Transfer Rider			$1,903,575			$0
Economic Development Rider			$0	271,566	$0.15	$40,735
Big Sandy 1 Operations Rider			$0		$0.00272	$375,927
Big Sandy Retirement Rider			$0	$14,303,281	6.2297%	$891,051
Environmental Surcharge			$0	$14,303,281	9.8027%	$1,402,108
Total			$18,901,993			$20,803,658
Embedded (Base) Fuel					$0.0284000	$3,925,118

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

SMALL GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (225)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-Peak	1,456	$0.15326	$223	1,456	$0.13755	$200
Off-Peak	1,556	$0.04940	$77	1,556	$0.05216	$81
Metered kWh	3,012			3,012		
Customer Charge	12.00	$15.10	$181	12.00	$19.50	$234
Number of Customers	12			12		
Fuel		$0.0020411	$6		$0.0020411	$6
Asset Transfer Rider			$59			
Economic Development Rider			$0	12	$0.15	$2
Big Sandy 1 Operations Rider			$0		$0.00272	$8
Big Sandy Retirement Rider			$0	$440	6.2297%	$27
Environmental Surcharge			$0	$440	9.8027%	$43
Total			$547			$602
Embedded (Base) Fuel					$0.0284000	$86

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

SMALL GENERAL SERVICE LOAD MANAGEMENT EXPERIMENTAL TIME-OF-DAY (227)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-Peak - Summer	23,647	$0.13538	$3,201	23,647	$0.11126	$2,631
On-Peak - Winter	32,745	$0.15553	$5,093	32,745	$0.12020	$3,936
Off-Peak	308,952	$0.08700	$26,879	308,952	$0.08476	$26,187
Metered kWh	365,344			365,344		
Customer Charge	912	$14.95	$13,634	912	$19.50	$17,783
Number of Customers	912			912		
Fuel		$0.0020411	$746		$0.0020411	$746
Asset Transfer Rider			$5,620			
Economic Development Rider			$0	912	$0.15	$137
Big Sandy 1 Operations Rider			$0		$0.00272	$994
Big Sandy Retirement Rider			$0	$41,292	6.2297%	$2,572
Environmental Surcharge			$0	$41,292	9.8027%	$4,048
Total			$55,173			$59,033
Embedded (Base) Fuel					$0.0284000	$10,376

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

SMALL GENERAL SERVICE - NON METERED (204, 213)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 500 kWh	2,710,207	$0.13160	$356,663	2,710,207	$0.11500	$311,674
Over 500 kWh	1,273,801	$0.07116	$90,644	1,273,801	$0.07057	$89,892
Metered kWh	3,984,008			3,984,008		
Customer Charge	17,594	$7.50	$131,955	17,594	$15.50	$272,707
Number of Customers	13,488			13,488		
Fuel		$0.0020411	$8,132		$0.0020411	$8,132
Asset Transfer Rider			$66,740			
Economic Development Rider				17,594	$0.15	$2,639
Big Sandy 1 Operations Rider					$0.00272	$10,837
Big Sandy Retirement Rider				$574,603	6.2297%	$35,796
Environmental Surcharge			$0	$574,603	9.8027%	$56,327
Total			$654,134			$788,003
Embedded (Base) Fuel					$0.0284000	$113,146

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

MEDIUM GENERAL SERVICE - RECREATIONAL LIGHTING (214)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
All kWh	1,563,141	$0.09004	$140,745	1,563,141	$0.10000	$156,314
Metered kWh	1,563,141			1,563,141		
Customer Charge	924	$13.50	$12,474	924	$19.50	$18,018
Number of Customers	924			924		
Fuel		$0.0020411	$3,191		$0.0020411	$3,191
Asset Transfer Rider			$15,521			
Economic Development Rider			$0	924	$0.15	$139
Big Sandy 1 Operations Rider			$0		$0.00283	$4,424
Big Sandy Retirement Rider			$0	$134,501	6.2297%	$8,379
Environmental Surcharge			$0	$134,501	9.8027%	$13,185
Total			$171,931			$203,649
Embedded (Base) Fuel					$0.0284000	$44,393

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

MEDIUM GENERAL SERVICE - SECONDARY (215, 216, 218)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 200 kWh per kW	333,938,968	$0.09862	$32,933,061	333,938,968	$0.10072	$33,634,333
Over 200 kWh per kW	162,854,869	$0.08460	$13,777,522	162,854,869	$0.08639	$14,069,032
Minimum kWh	0			-		
Metered kWh	496,793,837			496,793,837		
Billing kW						
Standard	2,076,023	$1.64	$3,404,678	2,076,023	$2.05	$4,255,847
Mining Minimum	0	$6.84	$0	-	$8.55	$0
Customer Charge	84,018	$13.50	$1,134,243	84,018	$19.50	$1,638,351
Number of Customers	84,048			84,048		
Fuel		$0.0020411	$1,014,017		$0.0020411	$1,014,017
Asset Transfer Rider			$5,593,600			
Economic Development Rider			$0	84,018	$0.15	$12,603
Big Sandy 1 Operations Rider - Energy			$0		$0.00141	$700,479
Big Sandy 1 Operations Rider - Demand			$0		$0.34	$705,848
Big Sandy Retirement Rider			$0	$40,907,548	6.2297%	$2,548,418
Environmental Surcharge			$0	$40,907,548	9.8027%	$4,010,044
Total			$57,857,120			$62,588,972
Embedded (Base) Fuel					$0.0284000	$14,108,945

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

MEDIUM GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (223)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	425,019	$0.14801	$62,907	425,019	$0.15757	$66,970
Off-peak kWh	629,992	$0.05130	$32,319	629,992	$0.05491	$34,593
Metered kWh	1,055,011			1,055,011		
Customer Charge	552	$3.00	$1,656	552	$3.85	$2,125
Number of Customers	552			552		
Fuel		$0.0020411	$2,153		$0.0020411	$2,153
Asset Transfer Rider			$10,924			$0
Economic Development Rider			$0	552	$0.15	$83
Big Sandy 1 Operations Rider			$0		$0.00283	$2,986
Big Sandy Retirement Rider			$0	$76,794	6.2297%	$4,784
Environmental Surcharge			$0	$76,794	9.8027%	$7,528
Total			$109,959			$121,222
Embedded (Base) Fuel					$0.0284000	$29,962

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

MEDIUM GENERAL SERVICE TIME-OF-DAY (229)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	1,411,570	$0.14801	$208,926	1,411,570	$0.15757	$222,421
Off-peak kWh	2,454,995	$0.05130	$125,941	2,454,995	$0.05491	$134,804
Metered kWh	3,866,565			3,866,565		
Customer Charge	912	$14.30	$13,042	912	$19.50	$17,784
Number of Customers	912			912		
Fuel		$0.0020411	$7,892		$0.0020411	$7,892
Asset Transfer Rider			$36,904			
Economic Development Rider			$0	912	$0.15	$137
Big Sandy 1 Operations Rider			$0		$0.00283	$10,942
Big Sandy Retirement Rider			$0	$276,278	6.2297%	$17,211
Environmental Surcharge			$0	$276,278	9.8027%	$27,083
Total			$392,706			$438,274
Embedded (Base) Fuel					$0.0284000	$109,810

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

MEDIUM GENERAL SERVICE - PRIMARY (217, 220)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 200 kWh per kW	5,716,583	$0.09054	$517,579	5,716,583	$0.09245	$528,498
Over 200 kWh per kW	3,592,839	$0.08098	$290,948	3,592,839	$0.08270	$297,128
Minimum kWh	47,677			47,677		
Metered Voltage Adj.	0			-		
Metered kWh	9,357,099			9,357,099		
Billing kW						
Standard	38,082	$1.59	$60,550	38,082	$1.98	$75,402
Mining Minimum	2,671	$6.84	$18,270	2,671	$8.55	$22,837
Customer Charge	1,009	$25.00	$25,225	1,009	$50.00	$50,450
Number of Customers	1,008			1,008		
Fuel		$0.0020411	$19,099		$0.0020411	$19,099
Asset Transfer Rider			$92,512			$0
Economic Development Rider				1,009	$0.15	$151
Big Sandy 1 Operations Rider - Energy					$0.00141	$13,194
Big Sandy 1 Operations Rider - Demand					$0.34	$13,856
Big Sandy Retirement Rider				$735,775	6.2297%	$45,837
Environmental Surcharge			$0	$735,775	9.8027%	$72,126
Total			$1,024,184			$1,138,577
Embedded (Base) Fuel					$0.0284000	$265,742

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

MEDIUM GENERAL SERVICE - SUBTRANSMISSION (236)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
First 200 kWh per kW	385,067	$0.08361	$32,195	385,067	$0.08538	$32,877
Over 200 kWh per kW	619,468	$0.07851	$48,634	619,468	$0.08018	$49,669
Minimum kWh	3,233			3,233		
Metered kWh	1,007,768			1,007,768		
Billing kW						
Standard	2,508	$1.55	$3,887	2,508	$1.96	$4,916
Mining Minimum	314	$6.84	$2,148	314	$8.55	$2,685
Customer Charge	119	$182.00	$21,658	119	$364.00	$43,316
Number of Customers	120			120		
Fuel		$0.0020411	$2,057		$0.0020411	$2,057
Asset Transfer Rider			$11,112			
Economic Development Rider			$0	119	$0.15	$18
Big Sandy 1 Operations Rider - Energy			$0		$0.00141	$1,421
Big Sandy 1 Operations Rider - Demand			$0		$0.34	$959
Big Sandy Retirement Rider			$0	$107,240	6.2297%	$6,681
Environmental Surcharge			$0	$107,240	9.8027%	$10,512
Total			$121,692			$155,111
Embedded (Base) Fuel					$0.0284000	$28,621

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

LARGE GENERAL SERVICE - SECONDARY (240, 242)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	558,760,756	$0.07795	$43,555,401	558,760,756	$0.08056	$45,013,767
Metered Voltage Adj.	60,999			60,999		
Metered kWh	558,821,755			558,821,755		
Billing kW	1,666,281	$4.02	$6,698,450	1,666,281	$5.03	$8,381,393
Excess kVA	49,112	$3.46	$169,928	49,112	$3.46	$169,928
Customer Charge	8,973	$85.00	$762,705	8,973	$85.00	$762,705
Number of Customers	8,976			8,976		
Fuel		$0.0020411	$1,140,623		$0.0020411	$1,140,623
Asset Transfer Rider			$5,211,705			$0
Economic Development Rider				8,973	$0.15	$1,346
Big Sandy 1 Operations Rider - Energy					$0.00139	$776,762
Big Sandy 1 Operations Rider - Demand					$0.45	$749,826
Big Sandy Retirement Rider				$39,985,189	6.2297%	$2,490,957
Environmental Surcharge			$0	$39,985,189	9.8027%	$3,919,628
Total			$57,538,811			$63,406,936
Embedded (Base) Fuel					$0.0284000	$15,870,538

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

LARGE GENERAL SERVICE LOAD MANAGEMENT TIME-OF-DAY (251)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh						
On-peak kWh	862,445	$0.12971	$111,868	862,445	$0.13421	$115,749
Off-peak kWh	1,097,494	$0.05116	$56,148	1,097,494	$0.05470	$60,033
Metered kWh	1,959,939			1,959,939		
Customer Charge	109	$81.80	$8,916	109	$85.00	$9,265
Number of Customers	108			108		
Fuel		$0.0020411	$4,000		$0.0020411	$4,000
Asset Transfer Rider			$17,670			$0
Economic Development Rider			$0	109	$0.15	$16
Big Sandy 1 Operations Rider					$0.00276	$5,409
Big Sandy Retirement Rider				$134,810	6.2297%	$8,398
Environmental Surcharge			$0	$134,810	9.8027%	$13,215
Total			$198,602			$216,086
Embedded (Base) Fuel					$0.0284000	$55,662

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

LARGE GENERAL SERVICE - PRIMARY (244, 246)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	112,193,710	$0.06514	$7,308,298	112,193,710	$0.06851	$7,686,391
Metered Voltage Adj.	(8,025)			(8,025)		
Metered kWh	112,185,685			112,185,685		
Billing kW	386,863	$3.89	$1,504,897	386,863	$4.89	$1,891,760
Excess kVA	62,872	$3.46	$217,537	62,872	$3.46	$217,537
Customer Charge	936	$127.50	$119,340	936	$127.50	$119,340
Number of Customers	936			936		
Fuel		$0.0020411	$228,985		$0.0020411	$228,985
Asset Transfer Rider			$896,161			$0
Economic Development Rider			$0	936	$0.15	$140
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$155,938
Big Sandy 1 Operations Rider - Demand			$0		$0.45	$174,088
Big Sandy Retirement Rider			$0	$7,059,122	6.2297%	$439,762
Environmental Surcharge			$0	$7,059,122	9.8027%	$691,985
Total			$10,275,219			$11,605,926
Embedded (Base) Fuel					$0.0284000	$3,186,073

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

LARGE GENERAL SERVICE - SUBTRANSMISSION (248)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	33,745,670	$0.04942	$1,667,711	33,745,670	$0.04670	$1,575,923
Metered Voltage Adj.	(20,476)			(20,476)		
Metered kWh	33,725,194			33,725,194		
Billing kW	110,848	$3.80	$421,222	110,848	$4.82	$534,287
Excess kVA	6,203	$3.46	$21,462	6,203	$3.46	$21,462
Customer Charge	240	$535.50	$128,520	240	$661.65	$158,796
Number of Customers	240			240		
Fuel		$0.0020411	$68,837		$0.0020411	$68,837
Asset Transfer Rider			$182,379			$0
Economic Development Rider			$0	240	$0.15	$36
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$46,878
Big Sandy 1 Operations Rider - Demand			$0		$0.45	$49,882
Big Sandy Retirement Rider			$0	$1,429,469	6.2297%	$89,052
Environmental Surcharge			$0	$1,429,469	9.8027%	$140,127
Total			$2,490,132			$2,685,280
Embedded (Base) Fuel					$0.0284000	$957,796

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

LARGE GENERAL SERVICE - TRANSMISSION (250)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	671,609	$0.04644	$31,190	671,609	$0.04579	$30,753
Metered Voltage Adj.	817			817		
Metered kWh	672,426			672,426		
Billing kW	5,277	$3.76	$19,842	5,277	$4.75	$25,066
Excess kVA	2,541	$3.46	$8,792	2,541	$3.45	$8,766
Customer Charge	12	$535.50	$6,426	12	$661.65	$7,940
Number of Customers	12			12		
Fuel		$0.0020411	$1,373		$0.0020411	$1,373
Asset Transfer Rider			($738)			$0
Economic Development Rider			$0	12	$0.15	$2
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$935
Big Sandy 1 Operations Rider - Demand			$0		$0.45	$2,375
Big Sandy Retirement Rider			$0	$56,739	6.2297%	$3,535
Environmental Surcharge			$0	$56,739	9.8027%	$5,562
Total			$66,883			$86,305
Embedded (Base) Fuel					$0.0284000	$19,097

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

QUANTITY POWER - SECONDARY (356)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	22,421,138	$0.03285	$736,534	22,421,138	$0.03398	$761,870
Metered kWh	22,421,138			22,421,138		
Billing kW						
On-Peak	52,430	$18.51	$970,479	52,430	$20.69	$1,084,777
Off-Peak Excess	463	$8.65	$4,005	463		
Off-Peak				41,767	$1.13	$47,197
Billing KVAR	4,387	$0.69	$3,027	4,387	$0.69	$3,027
Customer Charge	71	$276.00	$19,596	71	$276.00	$19,596
Number of Customers	72			72		
Fuel		$0.0020411	$45,764		$0.0020411	$45,764
Asset Transfer Rider			$165,841			$0
Economic Development Rider			$0	71	$0.15	$11
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$31,165
Big Sandy 1 Operations Rider - Demand			$0		$0.55	$28,837
Big Sandy Retirement Rider			$0	$1,339,719	6.2297%	$83,460
Environmental Surcharge			$0	$1,339,719	9.8027%	$131,329
Total			$1,945,247			$2,237,033
Embedded (Base) Fuel					$0.0284000	$636,760

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

QUANTITY POWER - PRIMARY (358)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	331,215,696	$0.03233	$10,708,203	331,215,696	$0.03279	$10,860,563
Metered Voltage Adj.	(44,845)			(44,845)		
Metered kWh	331,170,851			331,170,851		
Billing kW						
On-Peak	747,347	$15.00	$11,210,205	747,347	$17.46	$13,048,679
Off-Peak Excess	4,273	$5.56	$23,758	4,273		
Off-Peak				649,744	$1.10	$714,718
Alternate Feed	0	$4.34	$0	-	$6.25	$0
Billing KVAR	114,172	$0.69	$78,779	114,172	$0.69	$78,779
Facilities Charge			$150,000			$150,000
Customer Charge	479	$276.00	$132,204	479	$276.00	$132,204
Number of Customers	480			480		
Fuel		$0.0020411	$675,960		$0.0020411	$675,960
Asset Transfer Rider			$1,906,533			$0
Economic Development Rider			$0	479	$0.15	$72
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$460,327
Big Sandy 1 Operations Rider - Demand			$0		$0.55	$411,041
Big Sandy Retirement Rider			$0	$16,451,130	6.2297%	$1,024,856
Environmental Surcharge			$0	$16,451,130	9.8027%	$1,612,655
Total			$24,885,642			$29,169,854
Embedded (Base) Fuel					$0.0284000	$9,405,252

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

QUANTITY POWER - SUBTRANSMISSION (359)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	342,877,689	$0.03201	$10,975,515	342,877,689	$0.03242	$11,116,095
Metered Voltage Adj.	(466,815)			(466,815)		
Metered kWh	342,410,874			342,410,874		
Billing kW						
On-Peak	927,247	$10.13	$9,393,012	927,247	$10.74	$9,958,633
Off-Peak Excess	12,051	$1.20	$14,461	12,051		
Off-Peak				816,264	$1.08	$881,565
Billing KVAR	265,869	$0.69	$183,450	265,869	$0.69	$183,450
Customer Charge	307	$662.00	$203,234	307	$794.00	$243,758
Number of Customers	312			312		
Fuel		$0.0020411	$698,902		$0.0020411	$698,902
Asset Transfer Rider			$1,767,822			$0
Economic Development Rider			$0	307	$0.15	$46
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$475,951
Big Sandy 1 Operations Rider - Demand			$0		$0.55	$509,986
Big Sandy Retirement Rider			$0	$13,645,014	6.2297%	$850,043
Environmental Surcharge			$0	$13,645,014	9.8027%	$1,337,580
Total			$23,236,396			$26,256,009
Embedded (Base) Fuel					$0.0284000	$9,724,469

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

QUANTITY POWER - TRANSMISSION (360)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	66,309,341	$0.03176	$2,105,985	66,309,341	$0.03204	$2,124,551
Metered Voltage Adj.	(36,624)			(36,624)		
Metered kWh	66,272,717			66,272,717		
Billing kW						
On-Peak	145,830	$9.00	$1,312,470	145,830	$10.45	$1,523,924
Off-Peak Excess	2,250	$1.10	$2,475	2,250		
Off-Peak				142,365	$1.07	$152,331
Billing KVAR	76,675	$0.69	$52,906	76,675	$0.69	$52,906
Customer Charge	60	$1,353.00	$81,180	60	$1,353.00	$81,180
Number of Customers	60			60		
Fuel		$0.0020411	$135,271		$0.0020411	$135,271
Asset Transfer Rider			$369,296			$0
Economic Development Rider			$0	60	$0.15	$9
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$92,119
Big Sandy 1 Operations Rider - Demand			$0		$0.55	$80,207
Big Sandy Retirement Rider			$0	$2,225,080	6.2297%	$138,616
Environmental Surcharge			$0	$2,225,080	9.8027%	$218,118
Total			$4,059,582			$4,599,230
Embedded (Base) Fuel					$0.0284000	$1,882,145

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

COMMERCIAL AND INDUSTRIAL POWER TIME-OF-DAY - SUBTRANSMISSION (371)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	1,764,053,671	$0.02906	$51,263,400	1,764,053,671	$0.03242	$57,190,620
Metered kWh	1,764,053,671			1,764,053,671		
Billing kW						
On-Peak	2,915,472	$12.06	$35,160,592	2,915,472	$10.74	$31,312,169
Off-Peak	3,028,911	$1.20	$3,634,693	3,028,911	$1.08	$3,271,224
Minimum	87,948	$12.17	$1,070,327	87,948	$12.07	$1,061,532
Maximum	0			-		
Billing KVAR	202,954	$0.69	$140,038	202,954	$0.69	$140,038
Customer Charge	107	$794.00	$84,958	107	$794.00	$84,958
Number of Customers	108			108		
Fuel		$0.0020411	$3,600,649		$0.0020411	$3,600,649
Asset Transfer Rider			$6,060,400			$0
Economic Development Rider			$0	107	$0.15	$16
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$2,452,035
Big Sandy 1 Operations Rider - Demand			$0		$0.55	$1,651,881
Big Sandy Retirement Rider			$0	$47,065,349	6.2297%	$2,932,030
Environmental Surcharge			$0	$47,065,349	9.8027%	$4,613,675
Total			$101,015,058			$108,310,827
Embedded (Base) Fuel					$0.0284000	$50,099,124

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

COMMERCIAL AND INDUSTRIAL POWER TIME-OF-DAY - TRANSMISSION (372)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Billing kWh	292,348,340	$0.02880	$8,419,632	292,348,340	$0.03204	$9,366,841
Metered kWh	292,348,340			292,348,340		
Billing kW						
On-Peak	428,879	$10.98	$4,709,091	428,879	$10.45	$4,481,786
Off-Peak	414,632	$1.10	$456,095	414,632	$1.07	$443,656
Minimum	124,559	$11.09	$1,381,359	124,559	$11.76	$1,464,814
Maximum	0			-		
Billing KVAR	20,478	$0.69	$14,130	20,478	$0.69	$14,130
Customer Charge	24	$1,353.00	$32,472	24	$1,353.00	$32,472
Number of Customers	24			24		
Fuel		$0.0020411	$596,719		$0.0020411	$596,719
Asset Transfer Rider			$798,685			
Economic Development Rider			$0	24	$0.15	$4
Big Sandy 1 Operations Rider - Energy			$0		$0.00139	$406,364
Big Sandy 1 Operations Rider - Demand			$0		$0.55	$304,391
Big Sandy Retirement Rider			$0	$8,211,764	6.2297%	$511,568
Environmental Surcharge			$0	$8,211,764	9.8027%	$804,975
Total			$16,408,184			$18,427,718
Embedded (Base) Fuel					$0.0284000	$8,302,693

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

MUNICIPAL WATERWORKS (540)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
All kWh	3,841,169	$0.08300	$318,817	3,841,169	$0.08601	$330,379
Minimum kWh	22,870			22,870		
Metered kWh	3,864,039			3,864,039		
Minimum kW	714	$4.10	$2,927	714	$8.20	$5,855
Customer Charge	132	$22.90	$3,023	132	$22.90	$3,023
Number of Customers	132			132		
Fuel		$0.0020411	$7,887		$0.0020411	$7,887
Asset Transfer Rider			$31,629			
Economic Development Rider			$0	132	$0.15	$20
Big Sandy 1 Operations Rider			$0		$0.00248	$9,583
Big Sandy Retirement Rider			$0	$239,120	6.2297%	$14,896
Environmental Surcharge			$0	$239,120	9.8027%	$23,440
Total			$364,284			$395,083
Embedded (Base) Fuel					$0.0284000	$109,739

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

OUTDOOR LIGHTING (093, 094, 095, 097, 098, 099, 107, 109, 110, 111, 113, 116, 120, 122, 131)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
Overhead Lighting Service						
High Pressure Sodium						
100 watts, 9,500 Lumens (094)	235,073	$8.75	$2,056,892	235,073	$9.65	$2,268,458
150 watts, 16,000 Lumens (113)	221,760	$9.90	$2,195,425	221,760	$10.95	$2,428,273
200 watts, 22,000 Lumens (097)	21,655	$12.20	$264,188	21,655	$13.45	$291,256
250 watts, 28,000 Lumens (103)	0	$13.35	$0	0	$18.10	$0
400 watts, 50,000 Lumens (098)	2,062	$19.15	$39,480	2,062	$21.05	$43,397
Mercury Vapor						
175 watts, 7,000 Lumens (093)	10,578	$9.75	$103,133	10,578	$10.75	$113,711
400 watts, 20,000 Lumens (095)	1,023	$16.85	$17,242	1,023	$18.60	$19,032
Post Top Lighting Service						
High Pressure Sodium - PT - UG Circuit						
100 watts, 9,500 Lumens (111)	8,322	$13.10	$109,020	8,322	$14.45	$120,255
150 watts, 16,000 Lumens (122)	735	$21.45	$15,768	735	$23.70	$17,422
Mercury Vapor - PT - UG Circuit						
175 watts, 7,000 Lumens (099)	93	$11.20	$1,043	93	$12.30	$1,145
High Pressure Sodium - Shoebox with Decorative Pole						
100 watts, 9,500 Lumens (121)	0	$20.00	$0	0	$33.50	$0
250 watts, 28,000 Lumens (120)	10	$24.00	$248	10	$50.05	$517
400 watts, 50,000 Lumens (126)	0	$27.90	$0	0	$44.10	$0
Flood Lighting Service						
High Pressure Sodium - Floodlight, existing pole						
200 watts, 22,000 Lumens (107)	18,371	$13.60	$249,848	18,371	$15.00	$275,567
400 watts, 50,000 Lumens (109)	45,422	$18.85	$856,205	45,422	$20.80	$944,778
Metal Halide - Floodlight, existing pole						
250 watts, 20,500 Lumens (110)	1,383	$18.20	$25,164	1,383	$20.10	$27,791
400 watts, 36,000 Lumens (116)	9,594	$24.10	$231,215	9,594	$26.60	$255,200
1000 watts, 110,000 Lumens (131)	694	$52.20	$36,206	694	$67.35	$46,714
Metal Halide - Mongoose Light, existing pole						
250 watts, 20,500 Lumens (130)	0	$21.80	$0	0	$25.30	$0
400 watts, 36,000 Lumens (136)	0	$25.50	$0	0	$30.30	$0
Metered kWh	37,640,598			37,640,598		
Facilities Charge						
Pole	45,138	$2.85	$128,643	45,138	$3.15	$142,184
Span	48,868	$1.60	$78,189	48,868	$1.75	$85,519
Lateral	642	$6.25	$4,012	642	$6.90	$4,429
Fuel		$0.0020411	$76,829		$0.0020411	$76,829
Asset Transfer Rider			$767,571			$0
Big Sandy 1 Operations Rider			$0		$0.00147	$55,332
Big Sandy Retirement Rider			$0	$6,071,989	6.2297%	$378,267
Environmental Surcharge			$0	$6,071,989	9.8027%	$595,219
Total			$7,256,320			$8,191,296
Embedded (Base) Fuel					$0.0284000	$1,068,993

KENTUCKY POWER BILLING ANALYSIS
PROFORMA
TEST YEAR ENDED SEPTEMBER 30, 2014

STREET LIGHTING (528)

	Current Billing Units	Current Rate	Current Revenue	Proposed Billing Units	Proposed Rate	Proposed Revenue
OH Service on Distribution Poles						
High Pressure Sodium						
100 watts, 9,500 Lumens	95,940	$7.25	$695,566	95,940	$8.05	$772,319
150 watts, 16,000 Lumens	1,038	$8.30	$8,612	1,038	$9.25	$9,597
200 watts, 22,000 Lumens	28,868	$10.30	$297,345	28,868	$11.45	$330,543
400 watts, 50,000 Lumens	5,702	$16.05	$91,519	5,702	$17.80	$101,498
Service on New Wood Distribution Poles						
High Pressure Sodium						
100 watts, 9,500 Lumens	4,619	$10.25	$47,348	4,619	$11.35	$52,429
150 watts, 16,000 Lumens	242	$11.40	$2,754	242	$12.60	$3,044
200 watts, 22,000 Lumens	5,046	$13.15	$66,351	5,046	$14.60	$73,667
400 watts, 50,000 Lumens	955	$18.45	$17,619	955	$20.45	$19,529
Service on New Metal or Concrete Poles						
High Pressure Sodium						
100 watts, 9,500 Lumens	-	$18.90	$0	0	$20.95	$0
150 watts, 16,000 Lumens	-	$19.85	$0	0	$22.00	$0
200 watts, 22,000 Lumens	1,080	$25.25	$27,275	1,080	$28.00	$30,246
400 watts, 50,000 Lumens	-	$27.45	$0	0	$30.45	$0
Metered kWh	8,190,082			8,190,082		
Number of Customers	672			672		
Fuel		$0.0020411	$16,717		$0.0020411	$16,717
Asset Transfer Rider			$151,602			$0
Economic Development Rider			$0	672	$0.15	$101
Big Sandy 1 Operations Rider			$0		$0.00147	$12,039
Big Sandy Retirement Rider			$0	$1,172,414	6.2297%	$73,038
Environmental Surcharge			$0	$1,172,414	9.8027%	$114,928
Total			$1,422,709			$1,609,696
Embedded (Base) Fuel					$0.0284000	$232,598

Big Sandy Retirement Rider (BSRR)

Revenue Allocation and Adjustment Factor Calculation

KPCo Total Co Levelized Revenue Requirement	$	22,166,310	a
KPCo KY Retail Juris Demand Factor		0.986	b
KY Retail Juris Total Co Levelized Revenue Requirement	$	21,855,982	c = a*b
KY Residential Retail Revenue	$	243,238,523	d
All Other Classes Retail Revenue	$	331,069,707	e
KY Total Retail Revenue	$	574,308,230	f = d+e
All Other Classes Non-Fuel Retail Revenue	$	202,244,660	g
Residential Allocation	$	9,256,731	h = c(d/f)
All Other Allocation	$	12,599,251	i= c(e/f)
Total	$	21,855,982	
Residential BSRR Adjustment Factor		3.8056%	j = h/d
All Other BSRR Adjustment Factor		6.2297%	k = i/g
Revenue Verification	$	21,855,921	l=d*j+g*k

Environmental Surcharge

Revenue Allocation and Adjustment Factor Calculation

KPCo Total Co Revenue Requirement	$	37,892,616	a
KPCo KY Retail Juris Factor		0.9076	b
KY Retail Juris Total Co Revenue Requirement	$	34,391,339	c = a*b
KY Residential Retail Revenue	$	243,238,523	d
All Other Classes Retail Revenue	$	331,069,707	e
KY Total Retail Revenue	$	574,308,230	f = d+e
All Other Classes Non-Fuel Retail Revenue	$	202,244,660	g
Residential Allocation	$	14,565,869	h = c(d/f)
All Other Allocation	$	19,825,470	i= c(e/f)
Total	$	34,391,339	
Residential Enviromental Adjustment Factor		5.9883%	j = h/d
All Other Environmental Adjustment Factor		9.8027%	k = i/g
Revenue Verification	$	34,391,290	l=d*j+g*k

Capacity Charge

Revenue Allocation and Adjustment Factor Calculation

Revenue Requirement	$	6,200,000	a
Tariff IGS Proposed Total Revenue	$	189,000,671	b
All Other Classes Proposed Total Revenue	$	441,554,769	c
KY Total Retail Revenue	$	630,555,440	d = b + c
Tariff IGS Allocation	$	1,858,368	e = a(b/d)
All Other Allocation	$	4,341,632	f = a(c/d)
Total	$	6,200,000	g = e + f
Tariff IGS Energy		2,818,677,591	h
All Other Energy		3,673,418,023	i
Total		6,492,095,614	j = h + i
Tariff IGS Capacity Charge per kWh	$	0.000659	k = e/h
All Other Capacity Charge per kWh	$	0.001182	l = f / i
Revenue Verification	$	6,199,489	m=h*k+i*l

Big Sandy Retirement Rider (BSRR)

Revenue Allocation and Adjustment Factor Calculation

KPCo Total Co Levelized Revenue Requirement	$	22,166,310	a
KPCo KY Retail Juris Demand Factor		0.986	b
KY Retail Juris Total Co Levelized Revenue Requirement	$	21,855,982	c = a*b
KY Residential Retail Revenue	$	243,238,523	d
All Other Classes Retail Revenue	$	331,069,707	e
KY Total Retail Revenue	$	574,308,230	f = d+e
All Other Classes Non-Fuel Retail Revenue	$	202,244,660	g
Residential Allocation	$	9,256,731	h = c(d/f)
All Other Allocation	$	12,599,251	i= c(e/f)
Total	$	21,855,982	
Residential BSRR Adjustment Factor		3.8056%	j = h/d
All Other BSRR Adjustment Factor		6.2297%	k = i/g
Revenue Verification	$	21,855,921	l=d*j+g*k

ALLOCATION OF ASSET TRANSFER RIDER OVER/UNDER COLLECTION

Tariff Sheet	Asset Transfer Rider	Over/Under	Adjusted Asset Transfer Rider
RS	$16,434,417	$1,471,306	17,905,723
RS LM TOD	$28,287	$2,532	30,819
RS TOD	$304	$27	331
Total Residential	$16,463,009	$1,473,865	17,936,874
OL Total	$704,500	$63,071	767,571
SGS Metered	$1,747,159	$156,416	1,903,575
SGS LM TOD	$54	$5	59
SGS EXP TOD	$5,158	$462	5,620
SGS NM	$61,256	$5,484	66,740
Total SGS	$1,813,628	$162,367	1,975,995
MGS AF	$14,246	$1,275	15,521
MGS SEC	$5,133,977	$459,623	5,593,600
MGS LM TOD	$10,026	$898	10,924
MGS TOD	$33,872	$3,032	36,904
MGS PRI	$84,910	$7,602	92,512
MGS SUB	$10,199	$913	11,112
MGS	$5,287,231	$473,343	5,760,574
LGS SEC	$4,783,462	$428,243	5,211,705
LGS LM TOD	$16,218	$1,452	17,670
LGS PRI	$822,524	$73,637	896,161
LGS SUB	$167,393	$14,986	182,379
LGS TRAN	($677)	($61)	(738)
LGS	$5,788,920	$518,257	6,307,177
QP SEC	$152,214	$13,627	165,841
QP PRI	$1,749,874	$156,659	1,906,533
QP SUB	$1,622,561	$145,261	1,767,822
QP TRAN	$338,951	$30,345	369,296
QP	$3,863,601	$345,892	4,209,493
CIP TOD SUB	$5,562,420	$497,980	6,060,400
CIP TOD TRAN	$733,057	$65,628	798,685
CIP TOD	$6,295,477	$563,608	6,859,085
SL	$139,145	$12,457	151,602
MW	$29,030	$2,599	31,629
Total	$40,384,541	$3,615,459	44,000,000

KENTUCKY POWER COMPANY
Comparison of Current and Proposed Rates
Test Year Ended September 30, 2014
Case No.: 2014-00396

	CURRENT RATES				PROPOSED RATES							
TARIFF	Demand	Excess KVA/KVAR	Energy	Customer	Demand	% Change	Excess KVAR	% Change	Energy	% Change	Customer	% Change
	(2) $/kW	(3) $/kVAR	(5) c/kWh	(6) $/mo	(7) $/kW	(8)	(9) $/kVAR	(10)	(11) c/kWh	(12)	(13) $/mo	(14)
RS				8.00							16.00	100.0%
All kWh			8.590						9.035	5.2%		
Storage Water Htg. kWh												
80 gallons			4.940						5.216	5.6%		
100 gallons			4.940						5.216	5.6%		
120 gallons			4.940						5.216	5.6%		
Load Management Water Heating			4.940						5.216	5.6%		
RS-LM-TOD				10.55							18.70	77.3%
On-Peak			13.227						13.879	4.9%		
Off-Peak			4.940						5.216	5.6%		
Conservation and Load Management Credit			0.745						0.745	0.0%		
Separate Metering				3.00							3.85	28.3%
RS-TOD				10.55							18.70	77.3%
On-Peak			13.227						13.879	4.9%		
Off-Peak			4.940						5.216	5.6%		
RS-TOD 2 (no customers)				11.45							18.70	63.3%
On-Peak - Summer			11.406						10.885	-4.6%		
On-Peak - Winter			13.829						12.132	-12.3%		
Off-Peak			7.390						8.309	12.4%		
SGS				11.50							19.50	69.6%
First 500 kWh			13.160						11.500	-12.6%		
Over 500 kWh			7.116						7.057	-0.8%		
SGS Non-Metered				7.50							15.50	106.7%
First 500 kWh			13.160						11.500	-12.6%		
Over 500 kWh			7.116						7.057	-0.8%		
SGS-LM-TOD				15.10							19.50	29.1%
On-Peak			15.326						13.755	-10.3%		
Off-Peak			4.940						5.216	5.6%		
SGS-EXP-TOD				14.95							19.50	30.4%
On-Peak - Summer			13.538						11.126	-17.8%		
On-Peak - Winter			15.553						12.020	-22.7%		
Off-Peak			8.700						8.476	-2.6%		

KENTUCKY POWER COMPANY
Comparison of Current and Proposed Rates
Test Year Ended September 30, 2014
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TARIFF	CURRENT RATES Demand	Excess KVA/KVAR	Energy	Customer	PROPOSED RATES Demand	% Change	Excess KVAR	% Change	Energy	% Change	Customer	% Change
	(2) $/kW	(3) $/kVAR	(5) c/kWh	(6) $/mo	(7) $/kW	(8)	(9) $/kVAR	(10)	(11) c/kWh	(12)	(13) $/mo	(14)
MGS												
Secondary	1.64			13.50	2.05	25.0%					19.50	44.4%
kWh equal to 200 times Kw of mo. billing dem.			9.862						10.072	2.1%		
kWh in excess of 200 times kW of mo. billing dem.			8.460						8.639	2.1%		
Primary	1.59			25.00	1.99	25.2%					50.00	100.0%
kWh equal to 200 times Kw of mo. billing dem.			9.054						9.245	2.1%		
kWh in excess of 200 times kW of mo. billing dem.			8.098						8.270	2.1%		
Subtransmission	1.55			182.00	1.96	26.5%					364.00	100.0%
kWh equal to 200 times Kw of mo. billing dem.			8.361						8.538	2.1%		
kWh in excess of 200 times kW of mo. billing dem.			7.851						8.018	2.1%		
Minimum Charge	6.84				8.55	25.0%						
MGS - Recreational Lighting			9.004	13.50					10.000	11.1%	19.50	44.4%
MGS-LM-TOD				3.00							3.85	28.3%
On-Peak			14.801						15.757	6.5%		
Off-Peak			5.130						5.491	7.0%		
MGS-TOD				14.30							19.50	36.4%
On-Peak			14.801						15.757	6.5%		
Off-Peak			5.130						5.491	7.0%		
LGS												
Secondary	4.02	3.46	7.795	85.00	5.03	25.1%	3.46	0.0%	8.056	3.3%	85.00	0.0%
Primary	3.89	3.46	6.514	127.50	4.89	25.7%	3.46	0.0%	6.851	5.2%	127.50	0.0%
Subtransmission	3.80	3.46	4.942	535.50	4.83	27.1%	3.46	0.0%	4.670	-5.5%	661.65	23.6%
Transmission	3.76	3.46	4.644	535.50	4.75	26.3%	3.46	0.0%	4.579	-1.4%	661.65	23.6%
LGS-LM-TOD				81.80							85.00	3.9%
On-Peak			12.971						13.164	1.5%		
Off-Peak			5.116						5.471	6.9%		

KENTUCKY POWER COMPANY
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TARIFF	CURRENT RATES Demand	Excess KVA/KVAR	Energy	Customer	PROPOSED RATES Demand	% Change	Excess KVAR	% Change	Energy	% Change	Customer	% Change
	(2) $/kW	(3) $/kVAR	(5) c/kWh	(6) $/mo	(7) $/kW	(8)	(9) $/kVAR	(10)	(11) c/kWh	(12)	(13) $/mo	(14)
LGS-TOD (no customers)												
Secondary	7.64	3.46		85.00	10.20	33.5%	3.46	0.0%			85.00	0.0%
On-Peak			9.778						8.481	-13.3%		
Off-Peak			4.116						4.533	10.1%		
Primary	4.58	3.46		127.50	7.35	60.5%	3.46	0.0%			127.50	0.0%
On-Peak			7.959						8.187	2.9%		
Off-Peak			3.965						4.411	11.2%		
Subtransmission	0.24	3.46		535.50	1.08	350.0%	3.46	0.0%			661.65	23.6%
On-Peak			7.729						8.098	4.8%		
Off-Peak			3.891						4.374	12.4%		
Transmission	0.15	3.46		535.50	1.07	613.3%	3.46	0.0%			661.65	23.6%
On-Peak			7.655						8.002	4.5%		
Off-Peak			3.854						4.334	12.5%		
QP												
Secondary		0.69		276.00			0.69	0.0%			276.00	0.0%
On-Peak Billing Demand	18.51				20.69	11.8%						
Off-Peak Excess Billing Demand	8.65											
Off-Peak Billing Demand					1.13							
Minimum Demand					22.06							
All kWh			3.285						3.398	3.4%		
Primary		0.69		276.00			0.69	0.0%			276.00	0.0%
On-Peak Billing Demand	15.00				17.46	16.4%						
Off-Peak Excess Billing Demand	5.56											
Off-Peak Billing Demand					1.10							
Minimum Demand					18.80							
All kWh			3.233						3.279	1.4%		
Subtransmission		0.69		662.00			0.69	0.0%			794.00	19.9%
On-Peak Billing Demand	10.13				10.74	6.0%						
Off-Peak Excess Billing Demand	1.20											
Off-Peak Billing Demand					1.08							
Minimum Demand					12.07							
All kWh			3.201						3.242	1.3%		
Transmission		0.69		1,353.00			0.69	0.0%			1,353.00	0.0%
On-Peak Billing Demand	9.00				10.45	16.1%						
Off-Peak Excess Billing Demand	1.10											
Off-Peak Billing Demand					1.07							

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TARIFF	CURRENT RATES Demand (2) $/kW	Excess KVA/KVAR (3) $/kVAR	Energy (5) c/kWh	Customer (6) $/mo	PROPOSED RATES Demand (7) $/kW	% Change (8)	Excess KVAR (9) $/kVAR	% Change (10)	Energy (11) c/kWh	% Change (12)	Customer (13) $/mo	% Change (14)
Minimum Demand					11.76							
All kWh			3.176						3.204	0.9%		

KENTUCKY POWER COMPANY
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TARIFF	CURRENT RATES Demand (2) $/kW	Excess KVA/KVAR (3) $/kVAR	Energy (5) c/kWh	Customer (6) $/mo	PROPOSED RATES Demand (7) $/kW	% Change (8)	Excess KVAR (9) $/kVAR	% Change (10)	Energy (11) c/kWh	% Change (12)	Customer (13) $/mo	% Change (14)
CIP-TOD												
Primary		0.69	2.962	276.00			0.69	0.0%	3.279	10.7%	276.00	0.0%
On-Peak Billing Demand	16.77				17.46	4.1%						
Off-Peak Billing Demand	5.56				1.10	-80.2%						
Subtransmission		0.69	2.906	794.00			0.69	0.0%	3.242	11.6%	794.00	0.0%
On-Peak Billing Demand	12.06				10.74	-10.9%						
Off-Peak Billing Demand	1.20				1.08	-10.0%						
Transmission		0.69	2.880	1,353.00			0.69	0.0%	3.204	11.3%	1,353.00	0.0%
On-Peak Billing Demand	10.98				10.45	-4.8%						
Off-Peak Billing Demand	1.10				1.07	-2.7%						
Minimum Demand Charge												
Primary	16.88				18.80	11.4%						
Subtransmission	12.17				12.07	-0.8%						
Transmission	11.09				11.76	6.0%						
MW				22.90							22.90	0.0%
All kWh			8.300						8.601	3.6%		
Minimum Charge	4.10				8.20	100.0%						

KENTUCKY POWER COMPANY
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TARIFF	CURRENT RATES Demand	Excess KVA/KVAR	Energy	Customer		PROPOSED RATES Demand	% Change	Excess KVAR	% Change	Energy	% Change	Customer	% Change
	(2)	(3)	(5)	(6)		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	$/kW	$/kVAR	c/kWh	$/mo		$/kW		$/kVAR		c/kWh		$/mo	
OL													
High Pressure Sodium													
100 Watt (094)				8.75	per lamp / mth							9.65	10.3%
150 Watt (113)				9.90	per lamp / mth							10.95	10.6%
200 Watt (097)				12.20	per lamp / mth							13.45	10.2%
250 Watt (103)				13.35	per lamp / mth							18.10	35.6%
400 Watt (098)				19.15	per lamp / mth							21.05	9.9%
100 Watt Shoebox (121)				20.00	per lamp / mth							33.50	67.5%
250 Watt Shoebox (120)				24.00	per lamp / mth							50.05	108.5%
400 Watt Shoebox (126)				27.90	per lamp / mth							44.10	58.1%
Mercury Vapor													
175 Watt (093)				9.75	per lamp / mth							10.75	10.3%
400 Watt (095)				16.85	per lamp / mth							18.60	10.4%
Post Top													
100 Watt HPS (111)				13.10	per lamp / mth							14.45	10.3%
150 Watt HPS (122)				21.45	per lamp / mth							23.70	10.5%
175 Watt MV (099)				11.20	per lamp / mth							12.30	9.8%
Floodlights													
200 Watt HPS (107)				13.60	per lamp / mth							15.00	10.3%
400 Watt HPS (109)				18.85	per lamp / mth							20.80	10.3%
250 Watt MH (110)				18.20	per lamp / mth							20.10	10.4%
400 Watt MH (116)				24.10	per lamp / mth							26.60	10.4%
1000 Watt MH (131)				52.20	per lamp / mth							67.35	29.0%
250 Watt MH - Mongoose (130)				21.80	per lamp / mth							25.30	16.1%
400 Watt MH - Mongoose (136)				25.50	per lamp / mth							30.30	18.8%
Wood Pole				2.85	per pole / mth							3.15	10.5%
Overhead Span				1.60	per span / mth							1.75	9.4%
Underground Lateral				6.25	per lateral / mth							6.90	10.4%

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Comparison of Current and Proposed Rates
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TARIFF	CURRENT RATES Demand (2) $/kW	Excess KVA/KVAR (3) $/kVAR	Energy (5) c/kWh	Customer (6) $/mo		PROPOSED RATES Demand (7) $/kW	% Change (8)	Excess KVAR (9) $/kVAR	% Change (10)	Energy (11) c/kWh	% Change (12)	Customer (13) $/mo	% Change (14)
SL													
Overhead Service on Existing Distribution Poles													
100 Watt HPS				7.25	per lamp / mth							8.05	11.0%
150 Watt HPS				8.30	per lamp / mth							9.25	11.4%
200 Watt HPS				10.30	per lamp / mth							11.45	11.2%
400 Watt HPS				16.05	per lamp / mth							17.80	10.9%
Service on New Wood Distribution Poles													
100 Watt HPS				10.25	per lamp / mth							11.35	10.7%
150 Watt HPS				11.40	per lamp / mth							12.60	10.5%
200 Watt HPS				13.15	per lamp / mth							14.60	11.0%
400 Watt HPS				18.45	per lamp / mth							20.45	10.8%
Service on New Metal or Concrete Poles													
100 Watt HPS				18.90	per lamp / mth							20.95	10.8%
150 Watt HPS				19.85	per lamp / mth							22.00	10.8%
200 Watt HPS				25.25	per lamp / mth							28.00	10.9%
400 Watt HPS				27.45	per lamp / mth							30.45	10.9%

KENTUCKY POWER COMPANY
Comparison of Current and Proposed Rates
Test Year Ended September 30, 2014
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TARIFF	CURRENT RATES Demand	Excess KVA/KVAR	Energy	Customer		PROPOSED RATES Demand	% Change	Excess KVAR	% Change	Energy	% Change	Customer	% Change
	(2)	(3)	(5)	(6)		(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)
	$/kW	$/kVAR	c/kWh	$/mo		$/kW		$/kVAR		c/kWh		$/mo	
CATV													
Charge for attachments on a two-user pole				7.21	per pole / year							7.21	0.0%
Charge for attachments on a three-user pole				4.47	per pole / year							4.47	0.0%
COGEN / SPP I & II													
Standard Measurement				6.75	Single Phase							8.50	25.9%
				7.75	Polyhase							11.10	43.2%
TOD Measurement				7.15	Single Phase							9.05	26.6%
				8.10	Polyhase							11.40	40.7%
Energy Credit													
Standard Meter			2.90							3.79	30.7%		
TOD Meter													
On-Peak KWH			3.06							4.64	51.6%		
Off-Peak KWH			2.78							3.18	14.4%		
Capacity Credit													
Standard Energy Meter	2.84					3.70	30.3%						
TOD Energy Meter	6.82					8.87	30.1%						
NUG													
Subtransmission	3.65	0.69				0.00	-100.0%	0.00	-100.0%				
Transmission	2.30	0.69				0.00	-100.0%	0.00	-100.0%				
AFS													
Primary	4.34					6.25	44.0%						
Transfer Switch Maintenance				13.57								14.25	

Filing Requirement
807 KAR 5:001 Section 16 (4)(h)

Filing Requirement:

A summary of the utility's determination of its revenue requirements based on return on net investment rate base, return on capitalization, interest coverage, debt service coverage, or operating ratio, with supporting schedules;

Response:

Please see Section V, Schedules 1-3. Also, please see the testimony of Company Witness Wohnhas.

Filing Requirement
807 KAR 5:001 Section 16 (4)(i)

Filing Requirement:

A reconciliation of the rate base and capital used to determine its revenue requirements;

Response:

It is Kentucky Power Company's understanding that the KPSC authorizes utilities operating under its jurisdiction a return on capitalization. Capitalization is a readily determinable number which is audited by the Company's outside independent auditors. Theoretically, the only difference between capitalization and net investment rate base is a company's cash working capital. One primary benefit of authorizing a company return on capitalization is that it reduces the need and cost of a consultant to perform a study and testify in the case as to the appropriate level of cash working capital. The appropriate level of cash working capital is a number that is difficult to determine.

Please see the attached page for reconciliation of the rate base and capital used to determine Kentucky Power's revenue requirement.

KENTUCKY POWER COMPANY

Line No.	Description		
1	Total KPSC Jurisdiction Rate Base (Section V, Schedule 1, line 15)		$ 1,158,186,514
2	Cash	$ 1,749,762	
3	Accounts Receivable Net	76,799,180	
4	Other Property and Investments	5,548,144	
5	Allowance Inventory	13,622,289	
6	Accrued Utility Revenues	-	
7	Energy Trading Contracts	8,381,542	
8	Other Current Assets	61,439	
9	Unamortized Loss Reacquired Debt	611,282	
10	Property Taxes	4,528,249	
11	Other Deferred Debits	260,847,943	
12	Accounts Payable	(91,716,477)	
13	Taxes Accrued	(39,297,426)	
14	Interest Accrued	(5,298,052)	
15	Obligations Under Capital Leases	(4,506,282)	
16	Accumulated Provisions - Misc.	(70,656,153)	
15	Other Current and Accrued Liabilities	(48,101,128)	
16	Regulatory Liabilities	(5,755,097)	
17	Other Deferred Credits	(198,594,410)	(91,775,197) *
18	KPSC Jurisdiction Cash Working Capital (Section V, Schedule 4, column 6, line 43)		41,470,569
19	Difference		39,598,442
20	Total KPSC Jurisdiction Capitalization (Section V, Schedule 1, line 17)		$ 1,147,480,328

* Lines 2 through 17 are Total Company amounts. Lines 1, 18, and 20 are KPSC jurisdiction amounts.

Filing Requirement
807 KAR 5:001 Section 16 (4)(j)

Filing Requirement:

A current chart of accounts if more detailed than the Uniform System of Accounts prescribed by the commission;

Response:

Please see the following attachment for a current chart of accounts.

Account	Descr
1010001	Plant in Service
1011001	Capital Leases
1011006	Prov-Leased Assets
1011012	Accrued Capital Leases
1020001	Plant Purchd or Sold
1050001	Held For Fut Use
1060001	Const Not Classifd
1070000	Construction Work In Progress
1070001	CWIP - Project
1070910	Capitalized Softwr Bill Step 1
1080000	Accum Prov for Deprec of Plant
1080001	A/P for Deprec of Plt
1080002	A/P for Deprec of Plt-Transmn
1080005	RWIP - Project Detail
1080011	Cost of Removal Reserve
1080013	ARO Removal Deprec - Accretion
1110001	A/P for Amort of Plt
1201000	Nuclr Fuel in Proc of Refinmnt
1210001	Nonutility Property - Owned
1220001	Depr&Amrt of Nonutl Prop-Ownd
1220003	Depr&Amrt of Nonutl Prop-WIP
1240001	Other Investments - Associated
1240002	Oth Investments-Nonassociated
1240004	Other Inv-Employee Loans-LT
1240005	Spec Allowance Inv NOx
1240006	Other Investments - COLI
1240007	Deferred Compensation Benefits
1240009	Land & Land Rights
1240011	Unreal Gain on Fwd Commitments
1240025	Other Property - CWIP
1240027	Other Property - RWIP
1240028	Other Property - RETIRE
1240029	Other Property - CPR
1240030	NonCurrent Option Prem Payment
1240037	Intang Assets - Amortizable
1240044	Spec Allowances Inv SO2
1240092	Fbr Opt Lns-In Kind Sv-Invest
1290000	Pension Net Funded Position
1290001	Non-UMWA PRW Funded Position
1290002	SFAS 106 - Non-UMWA PRW
1290003	SFAS 87 - Pension
1310000	Cash
1340000	Other Special Deposits
1340002	Allowances
1340004	Worker's Comp Adv Premium
1340017	Spec Deposits - Gas Options
1340018	Spec Deposits - Elect Trading
1340043	Spec Deposit UBS Securities
1340044	Spec Deposits - SO2 Trading
1340048	Spec Deposits-Trading Contra
1340050	Spec Deposit Mizuho Securities

1340051	Spec Depost RBC
1350003	Cash Advances - Wages
1350004	Cash Adv-Employee Expenses
1410002	P/R Ded - Misc Loan Repayments
1420001	Customer A/R - Electric
1420003	Customer A/R - CMP
1420005	Employee Loans - Current
1420011	A/R - Retail Cust Rents
1420014	Customer A/R-System Sales
1420019	Transmission Sales Receivable
1420022	Cust A/R - Factored
1420023	Cust A/R-System Sales - MLR
1420024	Cust A/R-Options & Swaps - MLR
1420027	Low Inc Energy Asst Pr (LIEAP)
1420028	Emergency LIEAP
1420044	Customer A/R - Estimated
1420048	Emission Allowance Trading
1420050	PJM AR Accrual
1420052	Gas Accruals
1420053	AR Coal Trading
1420054	Accrued Power Brokers
1420057	Customer A/R - REC activity
1420101	Other Accounts Rec - Cust
1420102	AR Peoplesoft Billing - Cust
1430001	Other Accounts Rec-Regular
1430002	Allowances
1430006	Unbilled Accounts Receivable
1430018	Survivor Benefit Plan Premiums
1430019	Coal Trading
1430021	Emission Allowance Trading
1430022	2001 Employee Biweekly Pay Cnv
1430023	A/R PeopleSoft Billing System
1430081	Damage Recovery - Third Party
1430082	Acct Rec Gas - AEP Sys Pool
1430083	Damage Recovery Offset Demand
1430085	Gas Accruals GDA Transactions
1430086	AR Accrual NYMEX OTC Penults
1430087	PJM AR Accrual
1430089	A/R - Benefits Billing
1430090	Accrued Broker - Power
1430101	Other Accounts Rec - Misc
1430102	AR Peoplesoft Billing - Misc
1440001	Uncoll Accts-Elect Receivables
1440002	Uncoll Accts-Other Receivables
1440003	Uncoll Accts-Power Trading
1450000	Corp Borrow Prg (NR-Assoc)
1460001	A/R Assoc Co - InterUnit G/L
1460002	A/R Assoc Co - Allowances
1460006	A/R Assoc Co - Intercompany
1460007	A/R Assoc Co - OAR System
1460008	A/R Assoc Co - AEPSC Bills
1460009	A/R Assoc Co - InterUnit A/P

1460011	A/R Assoc Co - Multi Pmts
1460012	A/R Assoc-PCRB Interest
1460019	A/R-Assoc Co-AEPSC-Agent
1460024	A/R Assoc Co - System Sales
1460025	Fleet - M4 - A/R
1460028	Factored-A/R Chg off Limit Fee
1460045	A/R Assc Co-Realization Sharng
1510001	Fuel Stock - Coal
1510002	Fuel Stock - Oil
1510017	Lignite Inv on Hand Inc Transp
1510020	Fuel Stock Coal - Intransit
1520000	Fuel Stock Exp Undistributed
1530000	Residuals
1540001	M&S - Regular
1540002	M&S - Loaned/Rented
1540004	M&S - Exempt Material
1540005	Material Away for Repairs
1540006	M&S - Lime and Limestone
1540012	Materials & Supplies - Urea
1540013	Transportation Inventory
1540014	Indus Direct Charge Clearing
1540016	MMS - Truck Stock
1540019	M&S Validation Error Correctns
1540022	M&S-Lime & Limestone Intransit
1540023	M&S Inv - Urea In-Transit
1581000	SO2 Allowance Inventory
1581003	SO2 Allowance Inventory - Curr
1581004	NOx Allowance Inventory - Curr
1581006	An. NOx Comp Inv - Curr
1581009	CSAPR Current SO2 Inv
1630000	Stores Expense Undistributed
1630001	Strs Exp-Canton Centrl Wrhse
1630002	Strs Exp-Ft Wayne Centrl Wrhse
1630003	Strs Exp-Roanoke Centrl Wrhse
1630004	Strs Exp-T&D Satellite Storerm
1630005	Stores Exp - Rockport Plant
1630006	Stores Exp - Amos Plant
1630007	Stores Exp - Clinch River Plan
1630008	Stores Exp - Glen Lyn Plant
1630009	Stores Exp - Kanawha River Plt
1630010	Stores Exp - Mountaineer Plt
1630011	Stores Exp - Sporn Plant
1630013	Stores Exp - Conesville Plant
1630014	Stores Exp - Picway Plant
1630017	Stores Exp - Tanners Creek Plt
1630018	Stores Exp - Cook Nuclear Plan
1630019	Stores Exp - Big Sandy Plant
1630020	Stores Exp - Cardinal Plant
1630021	Stores Exp - Gavin Plant
1630022	Stores Exp - Kammer Plant
1630023	Stores Exp - Mitchell Plant
1630024	Stores Exp - Muskingum River

1630026	Stores Exp - Cook Coal Term
1630027	Stores Exp - Waterford Plant
1630029	Stores Exp - Fossil & Hydro
1630031	Stores Exp - T&D General
1630032	Stores Exp - Power Gen General
1630033	Stores Exp - All Busin Units
1630035	Coleto Creek Power Station
1630043	Comanche Station
1630044	Northeast Station - 1 & 2
1630045	Northeast Station - 3 & 4
1630046	Riverside Station
1630047	Southwest Station
1630048	Tulsa Power Station
1630049	Weleetka Power Station
1630053	Arsenal Hill Power Plant
1630055	Flint Creek Power Plant
1630056	Knox Lee Power Plant
1630057	Lieberman Power Plant
1630059	Pirkey Power Plant
1630060	Wilkes Power Plant
1630061	Welsh Power Plant
1630064	Oklaunion Power Station
1630070	Stores Exp - Houston Pipe Line
1630071	Stores Exp - Conesville Prep
1630089	Stores Exp - Shrevprt Chem Lab
1630091	Stores Exp - Central Mach Shop
1630108	Strs Exp - ACCT-AUP-ADJ
1630109	Strs Exp - ACCT-COUNT-ADJ
1630110	Strs Exp - ACCT-FRT-EXPENSE
1630111	Strs Exp - ACCT-INV-SCRAP
1630112	Strs Exp - PRICE VARIANCE
1630113	Strs Exp - ACCT-REC-INT
1630121	Strs Exp - Tulsa
1630125	Stores - Contract & Labor Svcs
1630126	Strs Exp - Transf Poly PH Pad
1630155	Stores Exp - Ceredo Plant
1630156	Stores Exp - Darby Plant
1630157	Stores Exp - Mattison Plant
1630158	Stores Exp-Lawrenceburg Plant
1630159	Stores Expense - Turk Plant
1630160	Stores Expense - Dresden Plant
1630999	Cash Discount Allocation Only
1650001	Prepaid Insurance
165000201	Prepaid Taxes
165000202	Prepaid Taxes
165000204	Prepaid Taxes
165000205	Prepaid Taxes
165000206	Prepaid Taxes
165000207	Prepaid Taxes
165000208	Prepaid Taxes
165000209	Prepaid Taxes
165000210	Prepaid Taxes

165000211	Prepaid Taxes
165000212	Prepaid Taxes
165000213	Prepaid Taxes
165000214	Prepaid Taxes
1650004	Prepaid Interest
1650005	Prepaid Employee Benefits
1650006	Other Prepayments
1650007	Corporate Owned Life Insurance
1650009	Prepaid Carry Cost-Factored AR
1650010	Prepaid Pension Benefits
165001112	Prepaid Sales Taxes
165001113	Prepaid Sales Taxes
165001114	Prepaid Sales Taxes
165001212	Prepaid Use Taxes
165001213	Prepaid Use Taxes
165001214	Prepaid Use Taxes
1650014	FAS 158 Qual Contra Asset
1650021	Prepaid Insurance - EIS
1650023	Prepaid Lease
1650035	PRW Without MED-D Benefits
1650036	PRW for Med-D Benefits
1650037	FAS158 Contra-PRW Exclud Med-D
1710048	Interest Receivable -FIT -LT
1710248	Interest Receivable -FIT -ST
1710348	Interest Receivable -SIT -LT
1710448	Interest Receivable. -SIT -ST
1720000	Rents Receivable
1730000	Accrued Utility Revenues
1730002	Acrd Utility Rev-Factored-Assc
1730005	Accrued Util. Rev.- SECA
1740000	Misc Current & Accrued Assets
174000400	State Excise Tax Refund
174001112	Non-Highway Fuel Tx Credt-2012
174001113	Non-Highway Fuel Tx Credt-2012
1740012	Pension Plan
1740014	Unreal Gain on Fwd Commitments
1740015	Option Premium Payments
1740017	Firm Transmission Rights
1740031	City of Mesa Cntrct Fee - Curr
1750001	Curr. Unreal Gains - NonAffil
1750002	Long-Term Unreal Gns - Non Aff
1750009	S/T Option Premium Purchases
1750021	S/T Asset MTM Collateral
1750022	L/T Asset MTM Collateral
1760010	S/T Asset for Commodity Hedges
1760011	L/T Asset for Commodity Hedges
1810001	Unamort Debt Exp - FMB
1810002	Unamort Debt Exp - Inst Pur Cn
1810004	Unamort Debt Exp - Debentures
1810006	Unamort Debt Exp - Sr Unsec Nt
1823001	Allowances
1823005	SFAS 109 DFIT

182300600	SFAS 109 DSIT
182300698	SFAS 109 DSIT
182300699	SFAS 109 DSIT
1823007	SFAS 112 Postemployment Benef
1823009	DSM Incentives
1823010	Energy Efficiency Recovery
1823011	DSM Lost Revenues
1823012	DSM Program Costs
1823022	HRJ 765kV Post Service AFUDC
1823054	HRJ 765kV Depreciation Expense
1823063	Unrecovered Fuel Cost
1823064	Oth Work In Prog - DSM Port
1823077	Unreal Loss on Fwd Commitments
1823078	Deferred Storm Expense
1823080	Deregulation Consumer Educat
1823099	Asset Retirement Obligations
1823105	Deferred Merger Cost - AEP/CSW
1823115	Defd Equity Carry Chg-Non Fuel
1823118	BridgeCo TO Funding
1823119	PJM Integration Payments
1823120	Other PJM Integration
1823121	Carry Chgs-RTO Startup Costs
1823122	Alliance RTO Deferred Expense
1823165	REG ASSET FAS 158 QUAL PLAN
1823166	REG ASSET FAS 158 OPEB PLAN
1823167	REG Asset FAS 158 SERP Plan
1823188	Deferred Carbon Mgmt Research
1823299	SFAS 106 Medicare Subsidy
1823301	SFAS 109 Flow Thru Defd FIT
1823302	SFAS 109 Flow Thru Defrd SIT
1823306	Net CCS FEED Study Costs
1823325	CCS FEED Study Reserve
1823329	ATR Under-Recovery
1823500	Mon Power Integration Cost
1830000	Prelimin Surv&Investgtn Chrgs
1830001	Interstate Project 765 kv Line
1830004	Prelim Survey & Invstgtn Resrv
1840000	Clearing Accounts
1840001	Bldg Servcs Oper Exp-Clearing
1840002	Accounts Pay Adj - Clearing
1840003	Procurement Card - Clearing
1840004	Undistributed Payroll-Clearing
1840005	Non-Product Payroll - Clearing
1840006	Telephone Expense - Clearing
1840007	Transfer of Funds - Clearing
1840020	Simulator Learning Center-Clrg
1840023	Factored Cust Accts Rec-Affil
1840025	Aviation - Clearing
1840026	Oth Accts Rec - Cash Clearing
1840027	Oth Accts Rec - A/R Clearing
1840028	Non T/L Payroll-Clearing
1840029	Transp-Assigned Vehicles

1840030	Transportation-Other
1840031	Affil Transactions-Cash Clrng
1840033	Alliance Rail Car - OH
1840035	IT Oper Company (OPCO) Clearng
1840040	Undist Labor Fringe Benfit Clr
1840041	Undist Incentive Frg Ben Clr
1840043	Treasury Clearing
1840045	Veh Clr - Conversion Use Only
1840046	PeopleSoft Treasury Wire Paymt
1840047	Pension Benefit Clearing
1840048	FIT Payment Clearing
1840051	Allowances - Clearing
1840054	Insurance Clearing
1840057	Cell Phone/Pager - Clearing
1840058	Severance Clearing
1840059	NTL Payroll Clearing-Non Labor
1840062	AEPSC Coal Lab Clearing
1840063	Corporate Charge Card Clearing
1850000	Temporary Facilities
1860000	MDD-Internal Billing Only
1860001	Allowances
1860002	Deferred Expenses
186000301	Deferred Property Taxes
186000310	Deferred Property Taxes
186000312	Deferred Property Taxes
186000313	Deferred Property Taxes
1860005	Unidentified Cash Receipts
1860007	Billings and Deferred Projects
1860018	Corp Separation Clearing
1860042	Exp Issue/Reaq Bonds & Stk
1860046	Railroad Cars Subleased
1860072	Deferred Coal Transactions
1860074	Merger Severance Offsets
1860076	Deferred Merger Relocation Exp
1860077	Agency Fees - Factored A/R
1860078	Incentive Expense-EVP Summary
1860079	Incentive Expense - Offset
186008102	Defd Property Tax - Cap Leases
186008103	Defd Property Tax - Cap Leases
186008104	Defd Property Tax - Cap Leases
186008105	Defd Property Tax - Cap Leases
186008106	Defd Property Tax - Cap Leases
186008107	Defd Property Tax - Cap Leases
186008108	Defd Property Tax - Cap Leases
186008113	Defd Property Tax - Cap Leases
186008114	Defd Property Tax - Cap Leases
1860085	BridgeCo TO Funding
1860087	Estimated Barging Bills
1860091	BridgeCo RTO Deferred Exp
1860092	Compatible Unit/Wrk 2k Sys Clr
1860094	Labor Accruals - Bal Sheet
1860096	PJM Payments

1860110	AEP Branding
1860114	ABD Major Construction Work
1860116	PJM Integration
1860136	NonTradition Option Premiums
1860150	Deferred Rate Case Expense
1860151	Transmission JV Deferred Costs
1860153	Unamortized Credit Line Fees
1860160	Deferred Expenses - Current
1860166	Def Lease Assets - Non Taxable
1860167	Def Lease Assets - Taxable
1860179	Local Credit Line Fees
1860999	Validation Error Correction
1880000	R&D Expenses
1890001	Loss Recqd Debt - FMB
1890004	Loss Rec Debt-Debentures
1900001	Accum Def Income Tax - Federal
1900006	ADIT Federal - SFAS 133 Nonaff
1900009	ADIT Federal - Pension OCI NAf
1900010	ADIT Federal - Pension OCI
1900011	ADIT Federal Non-UMWA PRW OCI
1900015	ADIT-Fed-Hdg-CF-Int Rate
1901001	Accum Deferred FIT - Other
1902001	Accum Defd FIT - Oth Inc & Ded
1903001	Acc Dfd FIT - FAS109 Flow Thru
1904001	Accum Dfd FIT - FAS 109 Excess
2010001	Common Stock Issued-Affiliated
2080000	Donations Recvd from Stckhldrs
2110000	Miscellaneous Paid-In Capital
2110009	MPIC - restricted stock units
2110018	DSIT Apportionment Adj.
2160001	Unapprp Retnd Erngs-Unrstrictd
2190001	OCI - FAS 133
2190004	OCI-Min Pen Liab FAS 158-SERP
2190006	OCI-Min Pen Liab FAS 158-Qual
2190007	OCI-Min Pen Liab FAS 158-OPEB
2190010	OCI for Commodity Hedges
2190015	Accum OCI-Hdg-CF-Int Rate
2210001	First Mortgage Bonds
2210004	Debentures
2210504	Debentures - Current Portion
2230000	Advances from Associated Co
2230500	Advances from Assoc Co-Current
2240002	Installment Purchase Contracts
2240005	Other Long Term Debt - Other
2240006	Senior Unsecured Notes
2240103	Notes Payable - Affiliated
2240502	Instl Purchase Contracts-Curr
2240503	Notes - Current Portion
2240505	Oth LTD - Other - Current
2240506	Senior Unsecured Notes-Current
2240603	Notes - Affiliated - Current
2260001	Unam Disc LTD-Debit-FMB

2260004	Unam Disc LTD-Dr-Debentures
2260006	Unam Disc LTD-Dr-Sr Unsec Note
2270001	Obligatns Undr Cap Lse-Noncurr
2270003	Accrued Noncur Lease Oblig
2282003	Accm Prv I/D - Worker's Com
2283000	Accm Prv for Pensions&Benefits
2283001	Deferred Compensation Plan
2283002	Supplemental Savings Plan
2283003	SFAS 106 Post Retirement Benef
2283005	SFAS 112 Postemployment Benef
2283006	SFAS 87 - Pensions
2283007	Perf Share Incentive Plan
2283013	Incentive Comp Deferral Plan
2283015	FAS 158 SERP Payable Long Term
2283016	FAS 158 Qual Payable Long Term
2283017	FAS 158 OPEB Payable Long Term
2283018	SFAS 106 Med Part-D
2284027	Econ. Development Fund NonCurr
2290006	Acc Prv for Potential Refund
2300001	Asset Retirement Obligations
2320001	Accounts Payable - Regular
2320002	Unvouchered Invoices
2320003	Retention
2320006	Allowance Settlements
2320011	Uninvoiced Fuel
2320050	Coal Trading
2320052	Accounts Payable - Purch Power
2320053	Elect Trad-Options&Swaps
2320054	Emission Allowance Trading
2320056	Gas Physicals
2320062	Broker Fees Payable
2320071	Gas Accruals GDA Trans-Payable
2320073	A/P Misc Dedic. Power
2320074	A/P - FTL - SWITCH Rentals
2320076	Corporate Credit Card Liab
2320077	INDUS Unvouchered Liabilities
2320079	Broker Commisn Spark/Merch Gen
2320081	AP Accrual NYMEX OTC & Penults
2320083	PJM Net AP Accrual
2320084	Uninvoiced OVEC Purch Power
2320086	Accrued Broker - Power
2320090	MISO AP Accrual
2320094	Customer A/P - REC Activity
2330000	Corp Borrow Program (NP-Assoc)
2330012	PCRB Note-Assoc-Current
2330212	PCRB Note-Assoc-Reacq-Current
2330999	Unbundling Adjustment
2340001	A/P Assoc Co - InterUnit G/L
2340002	Accnts Pay-Assoc-Unvouchrd
2340005	A/P Assoc Co - Allowances
2340011	A/P-Assc Co-AEPSC-Agent
2340012	A/P Assoc-PCRB Interest

2340025	A/P Assoc Co - CM Bills
2340026	A/P Assoc Co - R&D Bills
2340027	A/P Assoc Co - Intercompany
2340028	Factored-A/R Chg off Limit Fee
2340029	A/P Assoc Co - AEPSC Bills
2340030	A/P Assoc Co - InterUnit A/P
2340032	A/P Assoc Co - Multi Pmts
2340034	A/P Assoc Co - System Sales
2340035	Fleet - M4 - A/P
2340037	A/P Assoc-Global Borrowing Int
2340040	A/P Assc Co-On Behalf Of Trans
2340041	A/P Assc Co - Non-InterUnit GL
2340049	A/P Assoc -Realization Sharing
2340212	A/P Assoc-PCRB Reacq Int
2350001	Customer Deposits-Active
2350003	Deposits - Trading Activity
2350005	Deposits - Trading Contra
2360001	Federal Income Tax
236000101	Federal Income Tax
236000102	Federal Income Tax
236000190	Federal Income Tax
236000200	State Income Taxes
236000201	State Income Taxes
236000202	State Income Taxes
236000203	State Income Taxes
236000204	State Income Taxes
236000205	State Income Taxes
236000206	State Income Taxes
236000207	State Income Taxes
236000208	State Income Taxes
236000209	State Income Taxes
236000210	State Income Taxes
236000211	State Income Taxes
236000212	State Income Taxes
236000213	State Income Taxes
236000214	State Income Taxes
236000299	State Income Taxes
2360004	FICA
2360005	Federal Unemployment Tax
2360006	State Unemployment Tax
236000700	State Sales and Use Taxes
236000701	State Sales and Use Taxes
236000702	State Sales and Use Taxes
236000703	State Sales and Use Taxes
236000704	State Sales and Use Taxes
236000705	State Sales and Use Taxes
236000706	State Sales and Use Taxes
236000707	State Sales and Use Taxes
236000708	State Sales and Use Taxes
236000709	State Sales and Use Taxes
236000710	State Sales and Use Taxes
236000711	State Sales and Use Taxes

236000712	State Sales and Use Taxes
236000713	State Sales and Use Taxes
236000714	State Sales and Use Taxes
236000800	Real & Personal Property Taxes
236000801	Real & Personal Property Taxes
236000802	Real & Personal Property Taxes
236000803	Real & Personal Property Taxes
236000804	Real & Personal Property Taxes
236000805	Real & Personal Property Taxes
236000806	Real & Personal Property Taxes
236000807	Real & Personal Property Taxes
236000808	Real & Personal Property Taxes
236000809	Real & Personal Property Taxes
236000810	Real Personal Property Taxes
236000811	Real Personal Property Taxes
236000812	Real Personal Property Taxes
236000813	Real Personal Property Taxes
236000906	Federal Excise Taxes
236000907	Federal Excise Taxes
236000908	Federal Excise Taxes
236000909	Federal Excise Taxes
236000910	Federal Excise Taxes
236000911	Federal Excise Taxes
236000912	Federal Excise Taxes
236000913	Federal Excise Taxes
236000914	Federal Excise Taxes
236001201	State Franchise Taxes
236001202	State Franchise Taxes
236001203	State Franchise Taxes
236001204	State Franchise Taxes
236001205	State Franchise Taxes
236001206	State Franchise Taxes
236001207	State Franchise Taxes
236001208	State Franchise Taxes
236001209	State Franchise Taxes
236001210	State Franchise Taxes
236001211	State Franchise Taxes
236001212	State Franchise Taxes
236001213	State Franchise Taxes
236001314	State Business Occupatn Taxes
236001600	State Gross Receipts Tax
236001605	State Gross Receipts Tax
236001606	State Gross Receipts Tax
236001607	State Gross Receipts Tax
236001608	State Gross Receipts Tax
236001609	State Gross Receipts Tax
236001610	State Gross Receipts Tax
236001611	State Gross Receipts Tax
236001612	State Gross Receipts Tax
236001613	State Gross Receipts Tax
236001614	State Gross Receipts Tax
236001707	Municipal License Fees Accrd

236001708	Municipal License Fees Accrd
236001709	Municipal License Fees Accrd
236001710	Municipal License Fees Accrd
236001711	Municipal License Fees Accrd
236001712	Municipal License Fees Accrd
236001713	Municipal License Fees Accrd
236001714	Municipal License Fees Accrd
236002203	State License/Registration Tax
236002204	State License/Registration Tax
236002205	State License/Registration Tax
236002206	State License/Registration Tax
236002207	State License/Registration Tax
236002208	State License/Registration Tax
236002209	State License/Registration Tax
236002210	State License Registration Tax
236002211	State License Registration Tax
236002212	State License Registration Tax
236002213	State License Registration Tax
236002214	State License Registration Tax
236002502	Local Franchise Tax
236003301	Real/Pers Prop Tax-Cap Leases
236003302	Real/Pers Prop Tax-Cap Leases
236003303	Pers Prop Tax-Cap Leases
236003304	Pers Prop Tax-Cap Leases
236003310	Pers Prop Tax-Cap Leases
236003311	Pers Prop Tax-Cap Leases
236003312	Pers Prop Tax-Cap Leases
236003313	Pers Prop Tax-Cap Leases
236003314	Pers Prop Tax-Cap Leases
236003513	Real Prop Tax-Cap Leases
236003514	Real Prop Tax-Cap Leases
2360037	FICA - Incentive accrual
2360038	Reorg Payroll Tax Accrual
2360501	Fed Inc Tax-Short Term FIN48
2360502	State Inc Tax-Short Term FIN48
2360601	Fed Inc Tax-Long Term FIN48
2360602	State Inc Tax-Long Term FIN48
2360701	SEC Accum Defd FIT-Util FIN 48
2360702	SEC Accum Defd SIT - FIN 48
2360801	Federal Income Tax - IRS Audit
2360901	Accum Defd FIT- IRS Audit
2370001	Interest Accrued-FMB
2370002	Interest Accrued-Inst Pur Con
2370003	Interest Accrued-Notes Pay
2370004	Interest Accrued-Debentures
2370005	Interest Accrd-Other LT Debt
2370006	Interest Accrd-Sen Unsec Notes
2370007	Interest Accrd-Customer Depsts
2370009	Interest Accrued-Other
2370010	Interest Accrued - Affiliated
2370011	Interest Accrd-Short Term Debt
2370016	Interest Accrued - Tax

2370018	Accrued Margin Interest
2370048	Acrd Int.- FIT Reserve - LT
2370248	Acrd Int. - FIT Reserve - ST
2370448	Acrd Int. - SIT Reserve - ST
2380003	Div Decl - Common Stock-Affil
2410001	Federal Income Tax Withheld
2410002	State Income Tax Withheld
2410003	Local Income Tax Withheld
2410004	State Sales Tax Collected
2410005	FICA Tax Withheld
2410006	School District Tax Withheld
2410008	Franchise Fee Collected
2410009	KY Utility Gr Receipts Lic Tax
2420000	Misc Current & Accrued Liab
2420001	P/R Ded - Charitable Contribut
2420002	P/R Ded - Medical Insurance
2420003	P/R Ded - Dental Insurance
2420004	P/R Ded - Long Term Care
2420006	P/R Ded - Fitness Dues
2420007	P/R Ded - Savings Plan
2420009	Depend Care/Flex Medical Spend
2420010	P/R Ded - Dependent Life Ins
2420012	P/R Ded - Hyatt Legal Plan
2420013	P/R Ded - LTD Ins Premiums
2420014	P/R Ded - Savings Bonds
2420015	P/R Ded - Union Dues
2420016	P/R Ded-Crt Ordr/Grnshmt/Tx Lv
2420017	P/R Ded - AD&D and OAD&D Ins
2420018	P/R Ded-Reg&Spec Life Ins Prem
2420020	Vacation Pay - This Year
2420021	Vacation Pay - Next Year
2420022	P/R Ded - PAC
2420026	MICP
2420027	FAS 112 CURRENT LIAB
2420028	ESP - Employer Contrib Accrued
2420044	P/R Withholdings
2420045	Other Employee Benefits
2420046	FAS 158 SERP Payable - Current
2420049	P/R Ded - MetPay Insurance
2420051	Non-Productive Payroll
2420053	Perf Share Incentive Plan
2420057	Control Payroll Disburse Acct
2420063	Current Credit Risk Reserve
2420070	P/R Ded - Salvation Army
2420071	P/R Ded - Vision Plan
2420072	P/R - Payroll Adjustment
2420076	P/R Savings Plan - Incentive
2420086	Environ Remediation - SEMCO
2420087	Engage to Gain Incentive
2420088	Econ. Development Fund Curr
2420504	Accrued Lease Expense
2420506	Est Financing Cost - Bonds

2420511	Control Cash Disburse Account
2420512	Unclaimed Funds
2420514	Revenue Refunds Accrued
2420515	Severance Accrual
2420521	Interchange Power - Loop
2420532	Adm Liab-Cur-S/Ins-W/C
2420538	Federal Admin Fee
2420542	Acc Cash Franchise Req
2420554	P/R Ded - Stock Purchase Plan
2420558	Admitted Liab NC-Self/Ins-W/C
2420568	Prov Est Loss Obsolet M&S
242059201	Sales & Use Tax - Leased Equ
242059202	Sales & Use Tax - Leased Equ
242059203	Sales & Use Tax - Leased Equ
242059204	Sales & Use Tax - Leased Equ
242059205	Sales & Use Tax - Leased Equ
242059206	Sales & Use Tax - Leased Equ
242059207	Sales & Use Tax - Leased Equ
242059208	Sales & Use Tax - Leased Equ
242059209	Sales & Use Tax - Leased Equ
242059210	Sales Use Tax - Leased Equip
242059211	Sales Use Tax - Leased Equip
242059212	Sales Use Tax - Leased Equip
242059213	Sales Use Tax - Lease Equip
242059214	Sales Use Tax - Lease Equip
242059301	Real & Pers Prop Tax-Leased Eq
2420598	Est Fin Cost - Sen Unsec Notes
2420600	Unreal Loss on Fwd Commitments
2420601	Option Premium Receipts
2420607	Incentive Plan Payments
2420613	Public Liability Claim Deposit
2420618	Accrued Payroll
2420620	Energy Supply Non Gen ICP
2420623	Distr, Cust Ops & Reg Svcs ICP
2420624	Corp & Shrd Srv Incentive Plan
2420626	Safety Focus Incentive Plan
2420634	Sustnd Earngs Improv Severance
2420635	Generation Incentive Plan
2420642	Accrd SEI Misc Empl Benefits
2420643	Accrued Audit Fees
2420649	Reclamation Liability - Curr
2420650	P/R Ded - Health Savings Acct
2420651	Reorg Severance Accrual
2420653	Reorg Misc HR Exp Accrual
2420656	Federal Mitigation Accru (NSR)
2420657	Civil Penalties Accrual NSR
2420660	AEP Transmission ICP
2420664	ST State Mitigation Def (NSR)
2430001	Oblig Under Cap Leases - Curr
2430003	Accrued Cur Lease Oblig
2440001	Curr. Unreal Losses - NonAffil
2440002	LT Unreal Losses - Non Affil

2440007	Curr. Liab. - Deferred Futures
2440009	S/T Option Premium Receipts
2440021	S/T Liability MTM Collateral
2440022	L/T Liability MTM Collateral
2450010	S/T Liability-Commodity Hedges
2450011	L/T Liability-Commodity Hedges
2520000	Customer Adv for Construction
2530000	Other Deferred Credits
2530001	Deferred Revenues
2530004	Allowances
2530012	Unclaim Chks - Ret to Gen Fd
2530022	Customer Advance Receipts
2530044	Neigh Help Neig-Cust Donations
2530050	Deferred Rev -Pole Attachments
2530054	Unreal Loss on Fwd Commitments
2530065	Deferred Gain - Affiliated
2530067	IPP - System Upgrade Credits
2530084	NonCurrent Option Prem Receipt
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns
2530101	MACSS Unidentified EDI Cash
2530112	Other Deferred Credits-Curr
2530114	Federl Mitigation Deferal(NSR)
2530124	Contr In Aid of Constr Advance
2530137	Fbr Opt Lns-Sold-Defd Rev
2530177	Deferred Rev-Bonus Lease Curr
2530178	Deferred Rev-Bonus Lease NC
2540000	Other Regulatory Liabilities
2540006	SFAS 109 DFIT
2540007	SFAS 109 Excess DFIT
2540011	Over Recovered Fuel Cost
2540047	Unreal Gain on Fwd Commitments
2540071	KY Enhanced Reliability Liab
2540105	Home Energy Assist Prgm - KPCO
2540173	Green Pricing Option
2540185	ATR Over-Recovery
2543001	SFAS109 Flow Thru Def FIT Liab
2544001	SFAS 109 Exces Deferred FIT
2550001	Accum Deferred ITC - Federal
2811001	Acc Dfd FIT - Accel Amort Prop
2820001	ADIT- Other Property - Federal
2821001	Accum Defd FIT - Utility Prop
2822001	Accum Defd FIT - Other Prop
2823001	Acc Dfrd FIT FAS 109 Flow Thru
2824001	Acc Dfrd FIT - SFAS 109 Excess
2825001	Acc Dfd FIT-Utily Prop FIN48
2830001	ADIT - Other - Federal
2830002	ADIT - Other - State
283000202	ADIT - Other - State
2830006	ADIT Federal - SFAS 133 Nonaff
2831001	Accum Deferred FIT - Other
2831002	Accum Deferred SIT - Other
2831102	Acc Dfd SIT-WV Pollution Cntrl

2832001	Accum Dfrd FIT - Oth Inc & Ded
2833001	Acc Dfd FIT FAS 109 Flow Thru
2833002	Acc Dfrd SIT FAS 109 Flow Thru
2835002	Accum Deferred SIT - FIN48
4010001	Operation Exp - Nonassociated
4020000	Maintenance Expense
4030001	Depreciation Exp
4030021	AEPSC Bell Howell Inserter
4031001	Depr - Asset Retirement Oblig
4040001	Amort. of Plant
4060001	Amort of Plt Acq Adj
4073000	Regulatory Debits
4081002	FICA
4081003	Federal Unemployment Tax
408100508	Real & Personal Property Taxes
408100509	Real & Personal Property Taxes
408100510	Real Personal Property Taxes
408100511	Real Personal Property Taxes
408100512	Real Personal Property Taxes
408100513	Real Personal Property Taxes
408100600	State Gross Receipts Tax
408100608	State Gross Receipts Tax
408100609	State Gross Receipts Tax
408100612	State Gross Receipts Tax
408100613	State Gross Receipts Tax
408100614	State Gross Receipts Tax
4081007	State Unemployment Tax
408100812	State Franchise Taxes
408100813	State Franchise Taxes
408101413	Federal Excise Taxes
408101414	Federal Excise Taxes
408101713	St Lic Rgstrtion Tax-Fees
408101714	St Lic Rgstrtion Tax-Fees
408101812	St Publ Serv Comm Tax-Fees
408101813	St Publ Serv Comm Tax-Fees
408101814	St Publ Serv Comm Tax-Fees
408101900	State Sales and Use Taxes
408101912	State Sales and Use Taxes
408101913	State Sales and Use Taxes
408101914	State Sales and Use Taxes
408102014	State Business Occup Taxes
408102213	Municipal License Fees
408102214	Municipal License Fees
408102910	Real-Pers Prop Tax-Cap Leases
408102911	Real-Pers Prop Tax-Cap Leases
408102912	Real-Pers Prop Tax-Cap Leases
408102913	Real-Pers Prop Tax-Cap Leases
408102914	Real-Pers Prop Tax-Cap Leases
4081033	Fringe Benefit Loading - FICA
4081034	Fringe Benefit Loading - FUT
4081035	Fringe Benefit Loading - SUT
408103613	Real Prop Tax-Cap Leases

408103614	Real Prop Tax-Cap Leases
408200512	Real Personal Property Taxes
408200513	Real Personal Property Taxes
4091001	Income Taxes, UOI - Federal
409100212	Income Taxes UOI - State
409100213	Income Taxes UOI - State
409100214	Income Taxes UOI - State
4092001	Inc Tax, Oth Inc&Ded-Federal
409200212	Inc Tax Oth Inc Ded - State
409200213	Inc Tax Oth Inc Ded - State
409200214	Inc Tax Oth Inc Ded - State
4101001	Prov Def I/T Util Op Inc-Fed
4102001	Prov Def I/T Oth I&D - Federal
4111001	Prv Def I/T-Cr Util Op Inc-Fed
4111002	Prv Def I/T-Cr UtilOpInc-State
4111005	Accretion Expense
4112001	Prv Def I/T-Cr Oth I&D-Fed
4114001	ITC Adj, Utility Oper - Fed
4116000	Gain From Disposition of Plant
4118002	Comp. Allow Gains Title IV SO2
4118003	Comp. Allow. Gains-Seas NOx
4118004	Comp. Allow. Gains-Ann NOx
4180001	Non-Operatng Rental Income
4180003	Non-Opratng Rntal Inc-Maint
4180005	Non-Opratng Rntal Inc-Depr
4190001	Interest Inc - Assoc Non CBP
4190002	Int & Dividend Inc - Nonassoc
4190005	Interest Income - Assoc CBP
4191000	Allw Oth Fnds Usd Drng Cnstr
4210002	Misc Non-Op Inc-NonAsc-Rents
4210005	Misc Non-Op Inc-NonAsc-Timber
4210007	Misc Non-Op Inc - NonAsc - Oth
4210009	Misc Non-Op Exp - NonAssoc
4210031	Pwr Sales Outside Svc Territry
4210032	Pwr Purch Outside Svc Territry
4210039	Carrying Charges
4210043	Realiz Sharing West Coast Pwr
4211000	Gain on Dspsition of Property
4212000	Loss on Dspsition of Property
4261000	Donations
4263001	Penalties
4264000	Civic & Political Activities
4265002	Other Deductions - Nonassoc
4265004	Social & Service Club Dues
4265007	Regulatory Expenses
4265009	Factored Cust A/R Exp - Affil
4265010	Fact Cust A/R-Bad Debts-Affil
4265033	Transition Costs
4270002	Int on LTD - Install Pur Contr
4270005	Int on LTD - Other LTD
4270006	Int on LTD - Sen Unsec Notes
4270012	PCRB Interest Exp-Assoc

4280002	Amrtz Debt Dscnt&Exp-Instl Pur
4280006	Amrtz Dscnt&Exp-Sn Unsec Note
4281004	Amrtz Loss Rcquired Debt-Dbnt
4300001	Interest Exp - Assoc Non-CBP
4300003	Int to Assoc Co - CBP
4310001	Other Interest Expense
4310002	Interest on Customer Deposits
4310007	Lines Of Credit
4310022	Interest Expense - Federal Tax
4310023	Interest Expense - State Tax
4320000	Allw Brrwed Fnds Used Cnstr-Cr
4380001	Div Declrd - Common Stk - Asso
4400001	Residential Sales-W/Space Htg
4400002	Residential Sales-W/O Space Ht
4400005	Residential Fuel Rev
4420001	Commercial Sales
4420002	Industrial Sales (Excl Mines)
4420004	Ind Sales-NonAffil(Incl Mines)
4420006	Sales to Pub Auth - Schools
4420007	Sales to Pub Auth - Ex Schools
4420013	Commercial Fuel Rev
4420016	Industrial Fuel Rev
4440000	Public Street/Highway Lighting
4440002	Public St & Hwy Light Fuel Rev
4470001	Sales for Resale - Assoc Cos
4470002	Sales for Resale - NonAssoc
4470006	Sales for Resale-Bookout Sales
4470010	Sales for Resale-Bookout Purch
4470027	Whsal/Muni/Pb Ath Fuel Rev
4470028	Sale/Resale - NA - Fuel Rev
4470033	Whsal/Muni/Pub Auth Base Rev
4470035	Sls for Rsl - Fuel Rev - Assoc
4470066	PWR Trding Trans Exp-NonAssoc
4470074	Sale for Resale-Aff-Trnf Price
4470081	Financial Spark Gas - Realized
4470082	Financial Electric Realized
4470089	PJM Energy Sales Margin
4470093	PJM Implicit Congestion-LSE
4470098	PJM Oper.Reserve Rev-OSS
4470099	Capacity Cr. Net Sales
4470100	PJM FTR Revenue-OSS
4470101	PJM FTR Revenue-LSE
4470103	PJM Energy Sales Cost
4470106	PJM Pt2Pt Trans.Purch-NonAff.
4470107	PJM NITS Purch-NonAff.
4470109	PJM FTR Revenue-Spec
4470110	PJM TO Admin. Exp.-NonAff.
4470112	Non-Trading Bookout Sales-OSS
4470115	PJM Meter Corrections-OSS
4470116	PJM Meter Corrections-LSE
4470124	PJM Incremental Spot-OSS
4470126	PJM Incremental Imp Cong-OSS

4470128	Sales for Res-Aff. Pool Energy
4470131	Non-Trading Bookout Purch-OSS
4470141	PJM Contract Net Charge Credit
4470143	Financial Hedge Realized
4470144	Realiz.Sharing - 06 SIA
4470150	Transm. Rev.-Dedic. Whlsl/Muni
4470155	OSS Physical Margin Reclass
4470156	OSS Optim. Margin Reclass
4470168	Interest Rate Swaps-Power
4470170	Non-ECR Auction Sales-OSS
4470174	PJM Whlse FTR Rev - OSS
4470175	OSS Sharing Reclass - Retail
4470176	OSS Sharing Reclass-Reduction
4470180	Trading intra-book Reclass
4470181	Auction intra-book Reclass
4470202	PJM OpRes-LSE-Credit
4470203	PJM OpRes-LSE-Charge
4470204	PJM Spinning-Credit
4470206	PJM Trans loss credits-OSS
4470207	PJM transm loss charges - LSE
4470208	PJM Transm loss credits-LSE
4470209	PJM transm loss charges-OSS
4470214	PJM 30m Suppl Reserve CR OSS
4470220	PJM Regulation - OSS
4470221	PJM Spinning Reserve - OSS
4470222	PJM Reasctive - OSS
4491003	Prov Rate Refund - Retail
4500000	Forfeited Discounts
4510001	Misc Service Rev - Nonaffil
4540001	Rent From Elect Property - Af
4540002	Rent From Elect Property-NAC
4540004	Rent From Elect Prop-ABD-Nonaf
4540005	Rent from Elec Prop-Pole Attch
4560001	Oth Elect Rev - Affiliated
4560007	Oth Elect Rev - DSM Program
4560015	Other Electric Revenues - ABD
4560016	Financial Trading Rev-Unreal
4560031	MTM Credit Risk Reserve
4560043	Oth Elec Rv-Trn-Aff-Trnf Price
4560049	Merch Generation Finan -Realzd
4560050	Oth Elec Rev-Coal Trd Rlzd G-L
4560084	MTM-Coal Procurement
4560115	OSS FTR Auction MTM
4561002	RTO Formation Cost Recovery
4561003	PJM Expansion Cost Recov
4561005	PJM Point to Point Trans Svc
4561006	PJM Trans Owner Admin Rev
4561007	PJM Network Integ Trans Svc
4561019	Oth Elec Rev Trans Non Affil
4561026	PJM Transm Dist./Meter-Affil.
4561028	PJM Pow Fac Cre Rev Whsl Cu-NA
4561029	PJM NITS Revenue Whsl Cus-NAff

4561030	PJM TO Serv Rev Whls Cus-NAff
4561033	PJM NITS Revenue - Affiliated
4561034	PJM TO Adm. Serv Rev - Aff
4561035	PJM Affiliated Trans NITS Cost
4561036	PJM Affiliated Trans TO Cost
4561058	NonAffil PJM Trans Enhncmt Rev
4561059	Affil PJM Trans Enhancmnt Rev
4561060	Affil PJM Trans Enhancmnt Cost
4561061	NAff PJM RTEP Rev for Whsl-FR
4561062	PROVISION RTO Cost - Affi
4561063	PROVISION RTO Rev Affiliated
4561064	PROVISION RTO Rev WhslCus-NAf
4561065	PROVISION RTO Rev - NonAff
5000000	Oper Supervision & Engineering
5000001	Oper Super & Eng-RATA-Affil
5010000	Fuel
5010001	Fuel Consumed
5010003	Fuel - Procure Unload & Handle
5010005	Fuel - Deferred
5010012	Ash Sales Proceeds
5010013	Fuel Survey Activity
5010019	Fuel Oil Consumed
5010027	Gypsum handling/disposal costs
5010028	Gypsum Sales Proceeds
5010029	Gypsum handling/displ-Affiliat
5020000	Steam Expenses
5020001	Lime Expense
5020002	Urea Expense
5020003	Trona Expense
5020004	Limestone Expense
5020005	Polymer expense
5020007	Lime Hydrate Expense
5020008	Activated Carbon
5020013	Anhydrous Ammonia Expense
5020025	Steam Exp Environmental
5050000	Electric Expenses
5060000	Misc Steam Power Expenses
5060001	Dresden Misc Steam Pwer Exp
5060002	Misc Steam Power Exp-Assoc
5060003	Removal Cost Expense - Steam
5060004	NSR Settlement Expense
5060025	Misc Stm Pwr Exp Environmental
5070000	Rents
5090000	Allow Consum Title IV SO2
5090001	Allowance Consumption - NOx
5090002	Allowance Expenses
5090005	An. NOx Cons. Exp
5100000	Maint Supv & Engineering
5110000	Maintenance of Structures
5120000	Maintenance of Boiler Plant
5120025	Maint of Blr Plt Environmental
5130000	Maintenance of Electric Plant

5140000	Maintenance of Misc Steam Plt
5140025	Maint MiscStmPlt Environmental
5170000	Oper Supervision & Engineering
5170001	Oper Supervision & Engineering
5200000	Steam Expenses
5240000	Misc Nuclear Power Expenses
5280000	Maint Supv & Engineering
5300000	Maint of Reactor Plant Equip
5310000	Maintenance of Electric Plant
5320000	Maint of Misc Nuclear Plant
5320002	Fire Protection
5320009	Security Equipment
5350000	Oper Supervision & Engineering
5370000	Hydraulic Expenses
5370001	Fish & Wildlife Facilities
5370002	Recreation Facilities
5380000	Electric Expenses
5390000	Misc Hydr Power Generation Exp
5390001	Misc Hydr Pwr - Envir Poll Cnt
5420000	Maintenance of Structures
5420001	Maint of Strctures - Env Poll
5430000	Maint Rsrvoirs,Dams&Wtrways
5440000	Maintenance of Electric Plant
5450000	Maint of Misc Hydraulic Plant
5460000	Oper Supervision & Engineering
5470004	Fuel - Gas Turb - Purch / Hand
5480000	Generation Expenses
5490000	Misc Other Pwer Generation Exp
5490001	Misc Oth Pwr Gen - Gas Turbine
5530001	Maint of Gen Plant - Gas Turb
5550000	Purchased Power
5550001	Purch Pwr-NonTrading-Nonassoc
5550004	Purchased Power-Pool Capacity
5550005	Purchased Power - Pool Energy
5550027	Purch Pwr-Non-Fuel Portion-Aff
5550029	Purch Power-Assoc-Trnsfr Price
5550032	Gas-Conversion-Mone Plant
5550039	PJM Inadvertent Mtr Res-OSS
5550040	PJM Inadvertent Mtr Res-LSE
5550041	PJM Ancillary Serv.-Sync
5550046	Purch Power-Fuel Portion-Affil
5550074	PJM Reactive-Charge
5550075	PJM Reactive-Credit
5550076	PJM Black Start-Charge
5550077	PJM Black Start-Credit
5550078	PJM Regulation-Charge
5550079	PJM Regulation-Credit
5550080	PJM Hourly Net Purch.-FERC
5550083	PJM Spinning Reserve-Charge
5550084	PJM Spinning Reserve-Credit
5550090	PJM 30m Suppl Rserv Charge LSE
5550093	Peak Hour Avail charge - LSE

5550094	Purchased Power - Fuel
5550099	PJM Purchases-non-ECR-Auction
5550100	Capacity Purchases-Auction
5550101	Purch Power-Pool Non-Fuel -Aff
5550102	Pur Power-Pool NonFuel-OSS-Aff
5550107	Capacity purchases - Trading
5560000	Sys Control & Load Dispatching
5570000	Other Expenses
5570007	Other Pwr Exp - Wholesale RECs
5570008	Other Pwr Exp - Voluntary RECs
5570009	Other Pwr Exp- REC's - RETAIL
5570010	OH Auction Exp - Incremental
5600000	Oper Supervision & Engineering
5611000	Load Dispatch - Reliability
5612000	Load Dispatch-Mntr&Op TransSys
5614000	PJM Admin-SSC&DS-OSS
5614001	PJM Admin-SSC&DS-Internal
5614007	RTO Admin Default LSE.
5614008	PJM Admin Defaults OSS
5615000	Reliability,Plng&Stds Develop
5618000	PJM Admin-RP&SDS-OSS
5618001	PJM Admin-RP&SDS- Internal
5620001	Station Expenses - Nonassoc
5630000	Overhead Line Expenses
5640000	Underground Line Expenses
5650002	Transmssn Elec by Others-NAC
5650007	Tran Elec by Oth-Aff-Trn Price
5650012	PJM Trans Enhancement Charge
5650015	PJM TO Serv Exp - Aff
5650016	PJM NITS Expense - Affiliated
5650019	Affil PJM Trans Enhncement Exp
5650020	PROVISION RTO Affl Expense
5660000	Misc Transmission Expenses
5670001	Rents - Nonassociated
5670002	Rents - Associated
5680000	Maint Supv & Engineering
5690000	Maintenance of Structures
5691000	Maint of Computer Hardware
5692000	Maint of Computer Software
5693000	Maint of Communication Equip
5700000	Maint of Station Equipment
5710000	Maintenance of Overhead Lines
5720000	Maint of Underground Lines
5730000	Maint of Misc Trnsmssion Plt
5757000	PJM Admin-MAM&SC- OSS
5757001	PJM Admin-MAM&SC- Internal
5757002	SPP Admin-MAM&SC
5800000	Oper Supervision & Engineering
5810000	Load Dispatching
5820000	Station Expenses
5830000	Overhead Line Expenses
5840000	Underground Line Expenses

5841000	Oper of Energy Storage Equip
5850000	Street Lighting & Signal Sys E
5860000	Meter Expenses
5870000	Customer Installations Exp
5880000	Miscellaneous Distribution Exp
5890001	Rents - Nonassociated
5890002	Rents - Associated
5900000	Maint Supv & Engineering
5910000	Maintenance of Structures
5920000	Maint of Station Equipment
5930000	Maintenance of Overhead Lines
5930001	Tree and Brush Control
5930008	Maint Ovh Lines Strm Exp-OvUnd
5930010	Storm Expense Amortization
5940000	Maint of Underground Lines
5950000	Maint of Lne Trnf,Rglators&Dvi
5960000	Maint of Strt Lghtng & Sgnal S
5970000	Maintenance of Meters
5980000	Maint of Misc Distribution Plt
9010000	Supervision - Customer Accts
9020000	Meter Reading Expenses
9020001	Customer Card Reading
9020002	Meter Reading - Regular
9020003	Meter Reading - Large Power
9020004	Read-In & Read-Out Meters
9030000	Cust Records & Collection Exp
9030001	Customer Orders & Inquiries
9030002	Manual Billing
9030003	Postage - Customer Bills
9030004	Cashiering
9030005	Collection Agents Fees & Exp
9030006	Credit & Oth Collection Activi
9030007	Collectors
9030009	Data Processing
9040007	Uncoll Accts - Misc Receivable
9050000	Misc Customer Accounts Exp
9070000	Supervision - Customer Service
9070001	Supervision - DSM
9080000	Customer Assistance Expenses
9080001	DSM-Customer Advisory Grp
9080004	Cust Assistnce Exp - DSM - Ind
9080009	Cust Assistance Expense - DSM
9090000	Information & Instruct Advrtis
9100000	Misc Cust Svc&Informational Ex
9120000	Demonstrating & Selling Exp
9120001	Demo & Selling Exp - Res
9120003	Demo & Selling Exp - Area Dev
9200000	Administrative & Gen Salaries
9210001	Off Supl & Exp - Nonassociated
9210003	Office Supplies & Exp - Trnsf
9210007	Dresden Off Supl & Exp Nonasoc
9220000	Administrative Exp Trnsf - Cr

9220001	Admin Exp Trnsf to Cnstrction
9220004	Admin Exp Trnsf to ABD
9230001	Outside Svcs Empl - Nonassoc
9230002	Outside Svcs Empl - Assoc
9230003	AEPSC Billed to Client Co
9240000	Property Insurance
9250000	Injuries and Damages
9250001	Safety Dinners and Awards
9250002	Emp Accdent Prvntion-Adm Exp
9250004	Injuries to Employees
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv
9250007	Prsnal Injries&Prop Dmage-Pub
9250010	Frg Ben Loading - Workers Comp
9260000	Employee Pensions & Benefits
9260001	Edit & Print Empl Pub-Salaries
9260002	Pension & Group Ins Admin
9260003	Pension Plan
9260004	Group Life Insurance Premiums
9260005	Group Medical Ins Premiums
9260006	Physical Examinations
9260007	Group L-T Disability Ins Prem
9260009	Group Dental Insurance Prem
9260010	Training Administration Exp
9260012	Employee Activities
9260014	Educational Assistance Pmts
9260019	Employee Benefit Exp - COLI
9260021	Postretirement Benefits - OPEB
9260027	Savings Plan Contributions
9260036	Deferred Compensation
9260037	Supplemental Pension
9260040	SFAS 112 Postemployment Benef
9260050	Frg Ben Loading - Pension
9260051	Frg Ben Loading - Grp Ins
9260052	Frg Ben Loading - Savings
9260053	Frg Ben Loading - OPEB
9260055	IntercoFringeOffset- Don't Use
9260057	Postret Ben Medicare Subsidy
9260058	Frg Ben Loading - Accrual
9260060	Amort-Post Retirerment Benefit
9270000	Franchise Requirements
9280000	Regulatory Commission Exp
9280001	Regulatory Commission Exp-Adm
9280002	Regulatory Commission Exp-Case
9301000	General Advertising Expenses
9301001	Newspaper Advertising Space
9301002	Radio Station Advertising Time
9301003	TV Station Advertising Time
9301010	Publicity
9301012	Public Opinion Surveys
9301014	Video Communications
9301015	Other Corporate Comm Exp
9302000	Misc General Expenses

9302003	Corporate & Fiscal Expenses
9302004	Research, Develop&Demonstr Exp
9302006	Assoc Bus Dev - Materials Sold
9302007	Assoc Business Development Exp
9302458	AEPSC Non Affliated expenses
9310000	Rents
9310001	Rents - Real Property
9310002	Rents - Personal Property
9310004	Rents - Personal Prop - Assoc
9350000	Maintenance of General Plant
9350001	Maint of Structures - Owned
9350002	Maint of Structures - Leased
9350003	Maint of Prprty Held Fture Use
9350006	Maint of Carrier Equipment
9350012	Maint of Data Equipment
9350013	Maint of Cmmncation Eq-Unall
9350015	Maint of Office Furniture & Eq
9350016	Maintenance of Video Equipment
9350019	Maint of Gen Plant-SCADA Equ
9350023	Site Communications Services
9350024	Maint of DA-AMI Comm Equip

Filing Requirement
807 KAR 5:001 Section 16 (4)(k)

Filing Requirement:

The independent auditor's annual opinion report, with written communication from the independent auditor to the utility, if applicable, which indicates the existence of a material weakness in the utility's internal controls;

Response:

A copy of the independent auditor’s annual opinion report is attached. The report indicates that there was no material weakness.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2013 and 2012,and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Pnblic Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's iuternal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and our report dated February 25, 2014 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

Filing Requirement
807 KAR 5:001 Section 16 (4)(l)

Filing Requirement:

The most recent Federal Energy Regulatory Commission or Federal Communication Commission audit reports;

Response:

Please see attached document for the most recent Federal Energy Regulatory Commission audit report.

American Electric Power

AMERICAN ELECTRIC POWER

November 17, 1997

Mr. Bryan K. Craig
Acting Director, Division of Electric
and Hydropower Operations
Office of the Chief Accountant
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, DC 20426

Peter J. DeMaria
Executive Vice President
Administration and
Chief Accounting Officer

Dear Mr. Craig:

We have reviewed the audit report (copy attached) forwarded to us on October 30, 1997. The report summarizes the Results of the FERC audit staff's examination of the Books and Records of Kentucky Power Company for the period January 1, 1992 through December 31, 1996 in Docket No. FA96-40-000 and FA96-40-001.

Our comments on the three report issues are noted herein. Should you have any questions concerning our comments, please do not hesitate to contact the undersigned or Leonard V. Assante, Controller of AEPSC.

I. Compliance Exceptions

1. Accounting for Settlement Costs

Kentucky Power's Response

We agree with the recommendation that settlement costs on employment litigation be recorded below the line and have revised our accounting procedures accordingly. Attached is a copy of July 9, 1997 memorandum from G. R. Knorr, Assistant Controller of AEPSC, revising our procedures.

2. Miscellaneous Accounting Misclassification

Kentucky Power's Response

We agree with the recommendation concerning Account 228.3 (Accumulated Provision for Pensions and Benefits) and have revised our accounting procedures accordingly. Attached is a copy of our August 13, 1997 memorandum from G. S. Campbell/H. E. McCoy revising our procedures.

II. Deferred Matter

1. Accounting Classification for Service Company Billings

Kentucky Power's Response

The FERC audit report makes no recommendation on this issue pending further study by the FERC's Office of the Chief Accountant. We reserve our right to respond to this issue when the FERC's study is completed and released for comment.

I would like to take this opportunity to express our support for the new centralized approach to auditing AEP's electric operating subsidiaries. The new approach reduced the total time required to complete the audit of all AEP subsidiaries and reduced the cost to both AEP and the FERC. I would also like to thank Lucretia Smith and the fine staff of auditors that performed an efficient audit while minimizing disruption of our accounting operations.

Respectfully submitted,

Peter J. DeMaria

Peter J. DeMaria
PJD:bv
Attachments

FEDERAL ENERGY REGULATORY COMMISSION

WASHINGTON, D.C. 20426

In Reply Refer To:
OCA-DE/HO
Docket Nos. FA96-40-000
and FA96-40-001

OCT 30 1997

Kentucky Power Company
Attention: Mr. Len Assante
Controller
1 Riverside Plaza
Columbus, OH 43215

Ladies and Gentlemen:

The Division of Electric and Hydropower Operations of the Office of the Chief Accountant has examined the books and records of Kentucky Power Company for the period January 1, 1992, through December 31, 1996. The purpose of the examination was to evaluate your Company's compliance with Commission accounting and reporting regulations contained in the Uniform System of Accounts, Annual Report FERC Form No. 1, and the related regulations. The examination included selective tests of the accounting records, review of the internal control structure, and other tests and procedures considered necessary under the circumstances.

The Division of Electric and Hydropower Operations recommended corrective actions on certain findings of noncompliance with the Commission's accounting, financial reporting, and/or related regulations. Part I of the enclosed audit report describes the findings and recommendations. By letter dated August 29, 1997, your Company agreed to adopt the recommended corrective actions in Part I. I hereby approve and direct the recommended corrective actions in Part I.

The issue set forth in Part II on the accounting classification of service company billings is deferred for further study. The issue has been assigned as Docket No. FA96-40-001.

The Kentucky Power Commission did not respond with any objections to the foregoing matters.

The Commission delegated authority to act in this matter to the Acting Director, Division of Electric and Hydropower Operations under 18 C.F.R. § 375.303. This letter order constitutes final agency action on the corrective actions approved and directed in this report. Within 30 days of the date of this order, your Company may file a request for rehearing by the Commission under 18 C.F.R. § 385.713.

This letter order is without prejudice to the Commission's right to require hereafter any later adjustments arising from additional information that may come to its attention.

Sincerely,

Bryan K. Craig

Bryan K. Craig
Acting Director,
Division of Electric
and Hydropower Operations

Enclosure

Results of the Examination

of the

Books and Records

of

Kentucky Power Company
Docket Nos. FA96-40-000
and FA96-40-001

For the Period

1/1/92 through 12/31/96

Conducted by

Division of Audits
Office of the Chief Accountant
Federal Energy Regulatory Commission

TABLE OF CONTENTS

I. Compliance Exceptions

Kentucky Power Company (the Company) agreed to the recommended corrective actions on the following compliance matters:

1. Accounting for Settlement Costs

The Company used the wrong accounts to record costs to settle employment suits.

Recommendation

We recommend the Company revise procedures to ensure it records settlement payments in Account 426.5, Other Deductions, consistent with the requirements of the Uniform System of Accounts.

Facts

During 1995 and 1996, the AEP Service Company paid certain employment settlement costs. It recorded the settlement fees of $47,500 in Work Order No. 9988 -- AEPSC Overheads. The Service Company allocated this work order to all the AEP Service Company Work Orders based on salaries. The Service Company then billed out to the AEP System companies all its costs based upon SEC approved allocations for each individual work order. As a result, the Company recorded these settlement costs in every account charged as a result of the AEP Service Company billing. The effect of these transactions on the individual operating companies was not material.

Discussion of Accounting Requirements

Accounting Release No. 12, issued February 12, 1980, requires companies to charge expenditures resulting from compromise settlements or consent decrees to Account 426.5.

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2. Miscellaneous Accounting Classification

The Company classified a transaction in the wrong account. The following indicates the nature of the item misclassified, the account the Company used, and the proper account for such transactions:

Kentucky Power Company

Description	Account Used	Proper Account
Post-Retirement Benefits Other than Pensions - Liability	228.4	228.3

Recommendation

We recommend the Company adopt procedures to ensure that it records similar charges in the future consistent with the requirements of the Uniform Systems of Accounts.

II. Deferred Matter

1. Accounting Classification for Service Company Billings

AEPSC is a subsidiary of American Electric Power Corporation (AEP). It provides various services to affiliated AEP subsidiaries, including system planning, engineering, financial, accounting, public affairs, fuel procurement and customer services.

AEPSC is subject to the Public Utility Holding Company Act (PUCHA) which the Securities and Exchange Commission (SEC) administers. AEPSC maintains its accounts based on the SEC's Uniform System of Accounts for mutual service companies.

AEPSC first assigns all costs to various expense and other accounts. Then, it assigns all direct and indirect costs to various billable projects or work orders. 1/ Direct costs include labor and labor fringes, such as payroll taxes and employee benefits. Indirect amounts include overhead amounts not specifically assignable to the work orders, such as administrative and general salaries, miscellaneous general expenses, depreciation, maintenance of general plant, etc.

AEPSC bills interest on working capital loans and income taxes to the various operating companies as separate items apart from the normal fully allocated billable work orders.

AEPSC's invoices rendered to the Company and the other AEP subsidiaries include a cost breakdown for each work order between direct and overhead costs. The subsidiaries use the accounting classifications AEPSC provides to assign costs to its various accounts. Under this procedure, the AEP subsidiaries classified certain AEPSC administrative and general expenses, payroll taxes, etc., to accounts other than those that it would charge if it directly incurred the expenditures. For example, charges for direct labor costs to particular projects and accounts included additional costs related to employment taxes, pensions, other employee benefits, administrative and general expenses, and depreciation and maintenance of the office building owned by AEPSC.

Also, the AEP subsidiaries recorded income taxes and interest costs separately billed by AEPSC in Account 930.2, Miscellaneous General Expenses.

1/ When AEPSC performs specific work for more than one company within the holding company group, it uses an SEC approved method for assigning the cost among the various members.

Discussion of Accounting Requirements

General Instruction No. 14, Transactions with Associated Companies, of the Uniform System of Accounts States:

> Each utility shall keep its accounts and records so as to be able to furnish accurately and expeditiously statements of all transactions with associated companies. The statements may be required to show the general nature of the transactions, the amounts involved therein and the amounts included in each account prescribed herein with respect to such transactions. **Transactions with associated companies shall be recorded in the appropriate accounts for transactions of the same nature.** Nothing herein contained, however, shall be construed as restraining the utility from subdividing accounts for the purpose of recording separately transactions with associated companies. [Emphasis added.]

The Office of the Chief Accountant is currently studying the issue of classification of affiliated company charges on an industry-wide basis. Therefore, the Division of Audits did not make any recommendations on the subject pending completion of the study and any resulting FERC action. The accounting for the classification of affiliated company charges will be resolved in a separate docket, Docket No. FA96-40-001.

Date July 9, 1997

Subject Employment Settlement Costs

From G. R. Knorr

To File

Accounting Release 12 (AR-12) issued by the Office of the Chief Accountant at FERC requires all expenditures related to discriminatory employment practices to be recorded below-the-line as other income deductions. Fines and penalties are to be recorded in Account 426.3, Penalties, and all other costs, including settlement costs paid to the plaintiffs, are to be recorded in Account 426.5, Other deductions.

In the future, whenever such costs are paid by AEP Service Corporation, the expenditures should be classified to the appropriate FERC account (see above) and to Work Order No. 1011, Miscellaneous non-operating expenses. Work Order No. 1011 will transfer the incurred costs to first-tier AEP client companies for recording below-the-line.

G. R. Knorr

cc P. J. DeMaria
L. V. Assante
T. P. Bowman - Canton
G. E. Laurey
F. L. Sagan

AMERICAN ELECTRIC POWER

Date August 13, 1997

Subject **Reclassification of Benefits Liabilities**

From Greg Campbell/Hugh McCoy

To	Tim Bowman	- Canton
	Jerry Knorr	- Columbus
	George Laurey	- Columbus
	Maurice McIntyre	- Ft. Wayne
	Tom Mitchell	- Roanoke

Our practice in accounting for accumulated liabilities for pension benefits recorded under SFAS 87, postretirement benefits (OPEB) recorded under SFAS 106, and postemployment benefits recorded under SFAS 112 has been to record the liabilities to Account 228.4, Accumulated Miscellaneous Operating Provisions. We did not use Account 228.3, Accumulated Provision for Pensions and Benefits, because the description of Account 228.3 seems to exclude benefits funded through an irrevocable trust fund.

Nevertheless, during the course of the recent FERC audit, the FERC Staff informed us that our OPEB liability should be recorded to Account 228.3, rather than 228.4. The Staff also referred us to the FERC's May 7, 1993 OPEB accounting guidance in Docket No. AI93-4-000, which also provides for the use of Account 228.3. Therefore, the accumulated liability for benefits recorded under SFAS 87, 106, and 112 as of July 31, 1997 that is currently recorded in Account 228.4 should be reclassified in August 1997 business to Account 228.3, Accumulated Provision for Pensions and Benefits.

Please contact us if you should have any questions on this matter.

Hugh McCoy

Greg Campbell/Hugh McCoy

cc: Len Assante
Geoff Dean
Pete DeMaria
Bill Scott
Deloitte & Touche

\hem\ferc-aud\liab-rec

Intra-System

Filing Requirement
807 KAR 5:001 Section 16 (4)(m)

Filing Requirement:

The most recent Federal Energy Regulatory Commission Form 1 (electric), Federal Energy Regulatory Commission Form 2 (gas), or Public Service Commission Form T (telephone);

Response:

Please see the attached copy of Kentucky Power Company's most recent FERC Form 1 for year ended December 31, 2013.

THIS FILING IS		
Item 1: ☒ 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** 2013/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 Earnings	118-119
Statement of Cash Flows	120-121
Notes to Financial Statements	122-123

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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

IDENTIFICATION

01 Exact Legal Name of Respondent Kentucky Power Company	02 Year/Period of Report End of 2013/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)* 04/11/2014

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name F. Scott Travis 02 Title Assistant Controller	03 Signature F. Scott Travis	04 Date Signed *(Mo, Da, Yr)* 04/11/2014

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.

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".

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	N/A
65	Pumped Storage Generating Plant Statistics	408-409	N/A
66	Generating Plant Statistics Pages	410-411	N/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	04/11/2014	End of 2013/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	04/11/2014	End of 2013/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.

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.

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.

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

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) [ ] 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	04/11/2014	End of 2013/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

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	04/11/2014	End of 2013/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	04/11/2014	2013/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 ($)(2) (d)	Non-Equity Incentive Plan Compen-sation ($)(3) (f)	Change in Pension Value and Non-qualified Deferred Compen-sation Earnings ($)(4) (g)	All Other Compen-sation Earnings ($)(5) (h)	Total ($) (i)
Nicholas K. Akins — Chairman of the Board and Chief Executive Officer	1,204,615	—	6,720,167	2,430,000	155,741	102,065	10,612,588
Brian X. Tierney — Executive Vice President and Chief Financial Officer	675,086	—	1,893,044	875,500	0	77,689	3,521,319
Robert P. Powers — Executive Vice President and Chief Operating Officer	675,086	—	1,893,044	875,500	0	78,184	3,521,814
David M. Feinberg(6) — Executive Vice President and General Counsel	552,115	—	1,050,302	585,000	36,057	55,309	2,278,783
Lana L. Hillebrand(7) — Senior Vice President and Chief Administrative Officer	471,808	—	1,146,251	480,000	8,193	64,386	2,170,638

(1) Amounts in the salary column are composed of executive salaries paid for the year shown, which include 261 days of pay for 2013, 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 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2013 for a discussion of the relevant assumptions used in calculating these amounts. With respect to the performance units, the estimates of the grant date fair values determined in accordance with FASB ASC Topic 718 assumes the vesting of 100% of the performance units awarded. The value realized for the performance units, if any, will depend on the Company's performance during a three-year performance and vesting period. The potential payout can range from 0 percent to 200 percent of the target number of performance units, plus any dividend equivalents. Therefore, the maximum amount payable for the 2013 performance units is equal to $9,807,454 for Mr. Akins, $2,807,952 for Messrs. Power and Tierney, $1,352,936 for Mr. Feinberg and $1,220,475 for Ms. Hillebrand; and the maximum amount payable for the 2012 performance units is equal to $6,809,551 for Mr. Akins, $2,762,708 for Messrs. Power and Tierney and $1,381,354 for Mr. Feinberg. The 2011 performance units vested on December 31, 2013 and are shown in the Option Exercises and Stock Vested Table for 2013.The restricted stock units vest over a forty month period.

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

(4) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. See the Pension Benefits Table on page 56, and related footnotes for additional information. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2013 for a discussion of the relevant assumptions. No named executive officer received preferential or above-market earnings on deferred compensation. The actual change in pension value in 2013 for Mr. Tierney was ($163,271) and for Mr. Powers was ($236,687).

(5) Amounts shown in the All Other Compensation column for 2013 include: (a) Company contributions to the Company's Retirement Savings Plan, (b) Company contributions to the Company's Supplemental Retirement Savings Plan, (c) temporary living and relocation, (d) tax reimbursement and (e) perquisites. The amounts are listed in the following table:

All Other Compensation

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	04/11/2014	2013/Q4

FOOTNOTE DATA

Type	Nicholas K. Akins	Brian X. Tierney	Robert P. Powers	David M. Feinberg	Lana L. Hillebrand
Retirement Savings Plan Match	11,448	11,475	11,475	11,475	6,486
Supplemental Retirement Savings Plan Match	78,525	54,764	54,764	33,421	9,675
Temporary Living and Relocation	0	0	0	0	21,498
Tax Reimbursement(8)	0	0	0	0	16,554
Perquisites	12,092	11,450	11,945	10,413	10,173
Total	102,065	77,689	78,184	55,309	64,386

Perquisites provided in 2013 included: financial counseling and tax preparation, and, for Mr. Akins, director's accidental death insurance premium. Executive officers may also have the occasional personal use of event tickets when such tickets are not being used for business purposes, however, there is no associated incremental cost. From time to time executive officers may receive token gifts from third parties that sponsor sporting events (subject to our policies on conflicts of interest). None of the individual perquisites had a value exceeding $25,000 for a named executive officer.

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

(7) Ms. Hillebrand was not considered an executive officer prior to 2012. Ms. Hillebrand has an agreement with the Company pursuant to which we paid her $464,000 in 2012 to offset the loss of near-term compensation payments that she forfeited by coming to work at the Company. In addition, she was granted an additional $310,000 in restricted stock units on February 26, 2013 to offset the loss of stock units that she forfeited when she left her prior employer.

(8) We paid a tax reimbursement to Ms. Hillebrand for imputed income with respect to relocation and temporary living 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	04/11/2014	End of 2013/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	
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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
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15	Lana L. Hillebrand, 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	04/11/2014	End of 2013/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	04/11/2014	End of 2013/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)?

[ ] Yes
[X] 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	20130528-5163	05/28/2013	ER08-1329	AEP PJM OATT Formula Update	PJM OATT Attach H-14
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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	04/11/2014	End of 2013/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	This Report Is:	Date of Report	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) __ A Resubmission	04/11/2014	2013/Q4

IMPORTANT CHANGES DURING THE QUARTER/YEAR (Continued)

Item 1

Date Acquired Or Extended	Community (full name)	Period of Franchise & Termination (month/day/year)	Consideration ($ amount or "None")
Renewed March 11, 2013	City of Hindman, Knott County, KY	Ten (10) year franchise renewal expiring March 10, 2023	None
Renewed March 11, 2013	City of Jenkins, Letcher County, KY	Ten (10) year franchise renewal expiring March 10, 2023	None

Item 2 None

Item 3 None

Item 4 None

Item 5 None

Item 6 $200M Floating Rate Term Credit Agreement, due May 13, 2015. Funding due to transfer of 50% ownership interest of Mitchell Plant to Respondent. FERC Docket EC-13-28-000 Authority.

Item 7 None

Item 8 None

Item 9 None

Item 10 Lana L. Hillebrand appointed as Director and Vice President effective January 1, 2013
Julia A. Sloat appointed as Treasurer effective January 1, 2013
Michael Heyeck resigned as Vice President effective April 24, 2013

Item 11 (Reserved)

Item 12 Not Used

Item 13 None

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	04/11/2014	End of 2013/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	2,727,442,055	1,757,048,559
3	Construction Work in Progress (107)	200-201	128,599,148	44,281,292
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		2,856,041,203	1,801,329,851
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	961,039,344	622,134,082
6	Net Utility Plant (Enter Total of line 4 less 5)		1,895,001,859	1,179,195,769
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)		1,895,001,859	1,179,195,769
15	Utility Plant Adjustments (116)		0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		995,120	964,528
19	(Less) Accum. Prov. for Depr. and Amort. (122)		214,956	208,286
20	Investments in Associated Companies (123)		0	0
21	Investment in Subsidiary Companies (123.1)	224-225	0	0
22	(For Cost of Account 123.1, See Footnote Page 224, line 42)			
23	Noncurrent Portion of Allowances	228-229	0	2,361,232
24	Other Investments (124)		4,777,440	5,003,210
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)		11,446,242	0
30	Long-Term Portion of Derivative Assets (175)		3,483,625	6,840,814
31	Long-Term Portion of Derivative Assets – Hedges (176)		0	40,841
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		20,487,471	15,002,339
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		742,782	1,481,978
36	Special Deposits (132-134)		1,045,959	1,920,501
37	Working Fund (135)		0	0
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		15,011,626	12,676,053
41	Other Accounts Receivable (143)		75,379	150,660
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		77,562	141,538
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		8,914,645	9,241,088
45	Fuel Stock (151)	227	88,640,523	67,280,320
46	Fuel Stock Expenses Undistributed (152)	227	3,672,774	1,866,856
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	23,174,329	12,908,316
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	20,766,022	14,514,196

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	04/11/2014	End of 2013/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
53	(Less) Noncurrent Portion of Allowances		0	2,361,232
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)		1,406,808	1,569,795
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,026	1,285
60	Rents Receivable (172)		2,876,923	2,989,753
61	Accrued Utility Revenues (173)		856,776	816,939
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		7,760,914	12,993,718
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		3,483,625	6,840,814
65	Derivative Instrument Assets - Hedges (176)		79,097	62,756
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		0	40,841
67	Total Current and Accrued Assets (Lines 34 through 66)		171,464,396	131,089,789
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		1,900,818	2,205,280
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	216,720,708	214,230,662
73	Prelim. Survey and Investigation Charges (Electric) (183)		2,184,854	33,084,274
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	17,572,963	15,013,747
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)		636,519	670,167
82	Accumulated Deferred Income Taxes (190)	234	56,347,536	28,379,702
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		295,363,398	293,583,832
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		2,382,317,124	1,618,871,729

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	04/11/2014	end of 2013/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	614,648,268	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	179,690,924	190,818,915
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)	-5,419,702	-408,880
16	Total Proprietary Capital (lines 2 through 15)		839,369,490	479,610,035
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	730,000,000	530,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		611,325	778,050
24	Total Long-Term Debt (lines 18 through 23)		749,388,675	549,221,950
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		3,420,143	1,674,301
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		129,398	36,781
29	Accumulated Provision for Pensions and Benefits (228.3)		4,706,910	30,094,754
30	Accumulated Miscellaneous Operating Provisions (228.4)		932,000	0
31	Accumulated Provision for Rate Refunds (229)		0	1,635,430
32	Long-Term Portion of Derivative Instrument Liabilities		2,104,998	3,617,651
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		0	82,731
34	Asset Retirement Obligations (230)		20,526,045	3,902,259
35	Total Other Noncurrent Liabilities (lines 26 through 34)		31,819,494	41,043,907
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		21,618,569	30,336,777
39	Notes Payable to Associated Companies (233)		8,564,457	13,358,855
40	Accounts Payable to Associated Companies (234)		39,258,714	41,052,680
41	Customer Deposits (235)		25,211,285	23,484,965
42	Taxes Accrued (236)	262-263	15,459,433	6,548,715
43	Interest Accrued (237)		6,741,844	7,166,695
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	04/11/2014	end of 2013/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)		2,193,334	2,061,227
48	Miscellaneous Current and Accrued Liabilities (242)		15,134,242	15,736,581
49	Obligations Under Capital Leases-Current (243)		989,539	1,403,876
50	Derivative Instrument Liabilities (244)		3,873,703	6,749,162
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		2,104,998	3,617,651
52	Derivative Instrument Liabilities - Hedges (245)		58,923	271,288
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		0	82,731
54	Total Current and Accrued Liabilities (lines 37 through 53)		136,999,045	144,470,439
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		112,133	63,178
57	Accumulated Deferred Investment Tax Credits (255)	266-267	125,747	355,759
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	3,959,205	5,121,329
60	Other Regulatory Liabilities (254)	278	7,417,397	13,831,966
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	86,593,718	26,644,638
63	Accum. Deferred Income Taxes-Other Property (282)		364,219,669	252,501,733
64	Accum. Deferred Income Taxes-Other (283)		162,312,551	106,006,795
65	Total Deferred Credits (lines 56 through 64)		624,740,420	404,525,398
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		2,382,317,124	1,618,871,729

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	04/11/2014	End of 2013/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	666,591,378	631,455,274		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	454,800,026	408,136,355		
5	Maintenance Expenses (402)	320-323	48,603,114	46,464,797		
6	Depreciation Expense (403)	336-337	53,720,815	51,083,564		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	3,684,790	3,382,893		
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)		289,297	289,087		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	12,940,333	12,159,972		
15	Income Taxes - Federal (409.1)	262-263	2,940,817	11,025,629		
16	- Other (409.1)	262-263	2,297,830	2,315,915		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	60,544,574	61,561,067		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	43,410,193	51,377,005		
19	Investment Tax Credit Adj. - Net (411.4)	266	-230,012	-278,005		
20	(Less) Gains from Disp. of Utility Plant (411.6)		3,536	3,110		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		140,730	15,363		
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)		596,075,741	544,784,412		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		70,515,637	86,670,862		

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
666,591,378	631,455,274					2
						3
454,800,026	408,136,355					4
48,603,114	46,464,797					5
53,720,815	51,083,564					6
						7
3,684,790	3,382,893					8
38,616	38,616					9
						10
						11
289,297	289,087					12
						13
12,940,333	12,159,972					14
2,940,817	11,025,629					15
2,297,830	2,315,915					16
60,544,574	61,561,067					17
43,410,193	51,377,005					18
-230,012	-278,005					19
3,536	3,110					20
						21
140,730	15,363					22
						23
						24
596,075,741	544,784,412					25
70,515,637	86,670,862					26

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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)		70,515,637	86,670,862		
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)		27,938	48,800		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		153,935	257,457		
38	Allowance for Other Funds Used During Construction (419.1)		1,366,601	1,574,384		
39	Miscellaneous Nonoperating Income (421)		132,961	565,147		
40	Gain on Disposition of Property (421.1)		1,768,048			
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		3,449,483	2,445,788		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		7,425			
44	Miscellaneous Amortization (425)					
45	Donations (426.1)		372,321	322,570		
46	Life Insurance (426.2)					
47	Penalties (426.3)		3,876	18		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		247,726	304,052		
49	Other Deductions (426.5)		36,108,742	2,523,348		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		36,740,090	3,149,988		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263	58,651	56,600		
53	Income Taxes-Federal (409.2)	262-263	480,595	-757,316		
54	Income Taxes-Other (409.2)	262-263	203,260	15,788		
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	36,098	8,797		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	12,724,980	113,320		
57	Investment Tax Credit Adj.-Net (411.5)					
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-11,946,376	-789,451		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-21,344,231	85,251		
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)		1,062,442	1,051,134		
68	Other Interest Expense (431)		684,144	1,347,524		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		950,730	1,124,539		
70	Net Interest Charges (Total of lines 62 thru 69)		35,299,397	35,777,660		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		13,872,009	50,978,453		
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)		13,872,009	50,978,453		

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		190,818,915	171,840,462
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)		13,872,009	50,978,453
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		-25,000,000	(32,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-25,000,000	(32,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		179,690,924	190,818,915
	APPROPRIATED RETAINED EARNINGS (Account 215)			
39				
40				

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)		179,690,924	190,818,915
	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	04/11/2014	End of 2013/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)	13,872,009	50,978,453
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	57,444,221	54,505,073
5	Amortization of Regulatory Debits and Credits (Net)	289,297	289,087
6	Impairment of Long-Lived Assets	32,847,318	
7	Mark-to-Market of Risk Management Contracts	2,357,344	2,509,976
8	Deferred Income Taxes (Net)	4,445,499	10,079,539
9	Investment Tax Credit Adjustment (Net)	-230,012	-278,005
10	Net (Increase) Decrease in Receivables	-1,884,737	225,347
11	Net (Increase) Decrease in Inventory	11,120,998	-45,924,947
12	Net (Increase) Decrease in Allowances Inventory	-3,093,155	3,038,810
13	Net Increase (Decrease) in Payables and Accrued Expenses	-3,900,570	-14,366,705
14	Net (Increase) Decrease in Other Regulatory Assets	5,602,014	-8,849,896
15	Net Increase (Decrease) in Other Regulatory Liabilities	-1,167,593	933,562
16	(Less) Allowance for Other Funds Used During Construction	1,366,601	1,574,384
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-4,462,636	-2,657,705
19	Customer Deposits	1,726,321	1,410,888
20	Over/Under Recovered Fuel (Net)	-5,077,685	4,790,377
21	Pension Contributions		-4,902,000
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	108,522,032	50,207,470
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-85,304,750	-103,229,573
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	-1,366,601	-1,574,384
31	Other (provide details in footnote):		
32			
33	Acquired Assets	-562,650	-418,682
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-84,500,799	-102,073,871
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	4,780,930	656,838
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	04/11/2014	End of 2013/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
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
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-79,719,869	-31,085,186
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	Proceeds on Capital Leaseback	253,039	222,629
68	Notes Payable to Associated Companies	-4,794,398	13,358,855
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	-4,541,359	13,581,484
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	-25,000,000	-32,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	-29,541,359	-18,418,516
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-739,196	703,768
87			
88	Cash and Cash Equivalents at Beginning of Period	1,481,978	778,210
89			
90	Cash and Cash Equivalents at End of period	742,782	1,481,978

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	04/11/2014	2013/Q4

FOOTNOTE DATA

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

	2013 Cash Flow Incr / (Decr)	2012 Cash Flow Incr / (Decr)
Utility Plant, Net	$ (10,832,239)	$ (9,570,580)
Property and Investments, Net	2,835,671	16,846
Margin Deposits	874,542	1,488,868
Prepayments	4,220,903	3,134,974
Accrued Utility Revenues, Net	(39,836)	2,562,479
Unamortized Debt Expense	304,461	304,461
Other Deferred Debits, Net	2,017,242	935,732
Other Comprehensive Income, Net	(18,755)	(4,711)
Unamortized Discount/Premium on Long-Term Debt	166,725	166,725
Accumulated Provisions - Misc	(1,595,235)	1,248,722
Current and Accrued Liabilities, Net	(1,242,613)	(1,136,325)
Other Deferred Credits, Net	(1,153,502)	(1,804,896)
Total	**$ (4,462,636)**	**$ (2,657,705)**

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

	2013 Cash Flow Incr / (Decr)	2012 Cash Flow Incr / (Decr)
Sales of transformers to various associated companies	$ 103,460	$ 211,014
Sales of meters to various associated companies	62,090	149,005
Sale of Electrohydraulic Control System to associated company	-	296,819
Sale of 1,155 acres of land to Nelson Brothers LLC	4,615,380	-
Total	**$ 4,780,930**	**$ 656,838**

Schedule Page: 120 Line No.: 90 Column: b

KPCo had a noncash contribution of Mitchell Plant from Parent of $375,898,268.

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

NOTES TO FINANCIAL STATEMENTS

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

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

INDEX OF NOTES

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 electric 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.
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.
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.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
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.
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.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo which defined the sharing of costs and benefits associated with their respective generating plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.

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
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
PCA	Power Coordination Agreement.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utility Commission of Ohio.
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. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, 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.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

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 172,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

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

Effective January 1, 2014, the FERC approved a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo will be individually responsible for planning their respective capacity obligations and there will be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

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

Effective January 1, 2014, AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M and KPCo. Power and natural gas risk management activities are allocated based on the three member companies' respective equity positions and the SIA. KPCo shared in coal 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, natural gas and coal. The power, natural gas and coal contracts include physical transactions, OTC 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. For contracts entered and settled prior to January 1, 2014, power and natural gas risk management activities were allocated based on the Interconnection Agreement and the SIA. For contracts entered prior to January 1, 2014 and settled after January 1, 2014, power and natural gas risk management activities are allocated based on frozen MLR ratios as of December 31, 2013. KPCo shared in the revenues and expenses associated with these risk management activities with the other AEP East Companies, PSO and SWEPCo.

Under a unit power agreement with AEGCo, an affiliated company that was 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 natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of 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.

Prior to January 1, 2014, the Interconnection Agreement permitted the AEP East Companies to pool their generation assets on a cost basis. It established 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 were compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changed as generating assets were added, retired or sold and relative peak demand changed. The Interconnection Agreement calculated 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 was the MLR, which determined each member's percentage share of revenues and costs.

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.

Corporate Separation

On December 31, 2013, based on FERC and PUCO orders which approved the corporate separation of OPCo's generation assets and generation liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. Also on December 31, 2013, AGR subsequently transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

None of OPCo's regulatory assets and regulatory liabilities were transferred to KPCo.

Substantially all of the current income tax receivables and payables related to OPCo's generation activities prior to December 31, 2013 remained on OPCo's balance sheet. These current income tax receivables and payables are the responsibility of OPCo. Deferred tax assets and liabilities related to KPCo's acquired share of the Mitchell Plant were transferred to KPCo based upon the Mitchell Plant's related asset and liability values. Following these transfers, KPCo adjusted its deferred tax balances and related regulatory assets to reflect its deferred state tax rates.

On December 31, 2013, KPCo was assigned $200 million of Other Long-Term Debt from AGR related to a term credit facility.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

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

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

In addition, the FERC regulates the SIA, the System Transmission Integration Agreement and the Transmission Agreement, all of which are still active and allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement. In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated. In December 2013, the FERC issued orders approving the creation of a Power Coordination Agreement (PCA), effective January 1, 2014. Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent.

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 tax assets related to the accounting guidance for "Uncertainty in Income Taxes" as a reduction to current liabilities rather than a tax benefit.
- 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 interest receivable and interest accrued related to federal income tax and state income tax balances as separate current assets and current liabilities rather than as a single net amount.
- Prospective reporting for the transfer of a 50% interest in the Mitchell Plant rather than retrospective restatement to reflect the inclusion of 50% of the Mitchell Plant.
- The classification of unamortized loss on reacquired debt in deferred debits rather than in regulatory assets.
- The classification of accumulated deferred investment tax credits in deferred credits rather than in regulatory liabilities and deferred investment tax credits.
- The classification of plant probable of abandonment in Utility Plant and Construction Work in Progress rather than as Other Property, Plant and Equipment.
- The classification of certain other assets and liabilities as current instead of noncurrent.
- The classification of certain other assets and liabilities as noncurrent instead of current.

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

	2013	2012
For the Years Ended December 31,	**(in thousands)**	
Cash Was Paid for:		
Interest (Net of Capitalized Amounts)	$ 34,910	$ 35,516
Income Taxes (Net of Refunds)	6,100	23,089
Noncash Acquisitions Under Capital Leases	3,448	741
As of December 31,		
Construction Expenditures Included in Current and Accrued Liabilities	7,253	9,752

Special Deposits

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

Inventory

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

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	04/11/2014	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Accounts Receivable

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

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

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

Allowance for Uncollectible Accounts

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

Concentrations of Credit Risk and Significant Customers

KPCo does not have any significant customers that comprise 10% or more of its operating revenues as of December 31, 2013.

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 original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of 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, Notes Payable to Associated Companies and accounts payable approximate fair value because of the short-term maturity of these instruments.

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) 04/11/2014	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Fair Value Measurements of Assets and Liabilities

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

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

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. 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 FAC under-recovery is no longer probable of recovery, 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.

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 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 power, coal and natural gas 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 9.

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Maintenance

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

Income Taxes and Investment Tax Credits

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

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

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

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

Excise Taxes

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

Debt

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

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

Investments Held in Trust for Future Liabilities

AEP has several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The investment strategy for 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.

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	30.0 %
Fixed Income	55.0 %
Other Investments	15.0 %

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 and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. 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, which are publicly traded real estate securities.

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

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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 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, 2014, the date that KPCo’s 2013 FERC Form 1 was issued.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the year ended December 31, 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ 1,275	$ (20,860)	$ (19,994)
Change in Fair Value Recognized in AOCI	152	-	-	7,741	7,893
Amounts Reclassified from AOCI	(2)	60	1,402	-	1,460
Net Current Period Other Comprehensive Income	150	60	1,402	7,741	9,353
Pension and OPEB Adjustment Related to Mitchell Plant	-	-	-	5,221	5,221
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ 2,677	$ (7,898)	$ (5,420)

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Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the year ended December 31, 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Year Ended December 31, 2013

Gains and Losses on Cash Flow Hedges	**Amount of (Gain) Loss Reclassified from AOCI (in thousands)**
Commodity:	
Operating Revenues	$ (64)
Operation Expenses	76
Maintenance Expenses	(5)
Utility Plant	(11)
Subtotal - Commodity	(4)
Interest Rate and Foreign Currency:	
Interest on Long-term Debt	93
Subtotal - Interest Rate and Foreign Currency	93
Reclassifications from AOCI, before Income Tax (Expense) Credit	89
Income Tax (Expense) Credit	31
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	58
Pension and OPEB	
Amortization of Prior Service Cost (Credit)	(364)
Amortization of Actuarial (Gains)/Losses	2,521
Change in Funded Status	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	2,157
Income Tax (Expense) Credit	755
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1,402
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 1,460

The following table provides 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 year ended December 31, 2012. 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)

3. 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 below. 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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of December 31, 2013, the net book value of Big Sandy Plant, Unit 2 was $249 million, before cost of removal, including materials and supplies inventory and CWIP. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace a portion of the capacity from Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million. In November 2013, the KPSC denied the Attorney General's petition for rehearing. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase included cost recovery of the proposed transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order in the plant transfer case which modified and approved a settlement agreement that included the approval of the proposed transfer of the one-half interest in the Mitchell Plant to KPCo. The modified and approved settlement agreement also included KPCo's agreement to withdraw this base rate case request and file a base case proceeding no later than December 2014 with its current base rates to remain in effect until at least May 2015. In November 2013, KPCo withdrew this base rate request and the withdrawal was approved by the KPSC.

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 and to transfer at net book value AGR's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each), to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR, and the Mitchell Plant assets to APCo and KPCo. In January 2014, the FERC dismissed an Industry Energy Users-Ohio petition for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AGR. In December 2013, the transfer of the Mitchell Plant to KPCo was completed. See the “Plant Transfer” section.

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

In December 2013, the FERC issued orders approving the creation of a Power Coordination Agreement (PCA), effective January 1, 2014, conditioned upon certain compliance filings which were filed with the FERC in January 2014. The PCA was established among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, KPCo would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by orders from the Virginia SCC and the KPSC related to the proposed asset transfers and to position the company for the final stages of corporate separation. In December 2013, the FERC issued an order approving these additional filings. See the "Plant Transfer" section above.

If KPCo experiences a decrease in revenues or an increase 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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4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	**December 31, 2013**	**December 31, 2012**	**Remaining Recovery Period**
	(in thousands)		
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	$ 12,146	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	-	873	
Total Regulatory Assets Not Yet Being Recovered	12,146	13,019	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
RTO Formation/Integration Costs	786	998	various
Regulatory Assets Currently Not Earning a Return			
Income Tax Assets	155,600	128,656	22 years
Pension and OPEB Funded Status	32,458	52,048	11 years
Storm Related Costs	7,048	11,746	2 years
Postemployment Benefits	4,530	5,230	5 years
Medicare Subsidy	2,383	-	11 years
Other Regulatory Assets Being Recovered	1,770	2,534	various
Total Regulatory Assets Being Recovered	204,575	201,212	
Total FERC Account 182.3 Regulatory Assets	$ 216,721	$ 214,231	

Regulatory Liabilities:	**December 31, 2013**	**December 31, 2012**	**Remaining Refund Period**
	(in thousands)		
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	$ 3,259	$ 4,288	4 years
Income Tax Liabilities	998	1,167	22 years
Over-recovered Fuel Costs	2,851	7,928	1 year
Other Regulatory Liabilities Being Paid	309	449	various
Total FERC Account 254 Regulatory Liabilities	$ 7,417	$ 13,832	

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

COMMITMENTS

Construction and Commitments

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

The following table summarizes KPCo's actual contractual commitments as of December 31, 2013:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 198,192	$ 246,401	$ 232,240	$ 348,360	$ 1,025,193
Energy and Capacity Purchase Contracts	35,144	70,156	69,993	139,846	315,139
Construction Contracts for Capital Assets (b)	1,786	-	-	-	1,786
Total	$ 235,122	$ 316,557	$ 302,233	$ 488,206	$ 1,342,118

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

GUARANTEES

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

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, 2013, 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 12 for disclosure of lease residual value guarantees.

CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. 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.

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. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court’s dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme Court.

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NOTES TO FINANCIAL STATEMENTS (Continued)

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. 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 filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

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, 2013, 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.

6. IMPAIRMENT

Big Sandy Plant, Unit 2 FGD Project

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million primarily related to the Big Sandy Plant, Unit 2 FGD project. See the "Plant Transfer" section of Note 3.

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "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 an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2013**	**2012**	**2013**	**2012**
Discount Rate	4.70 %	3.95 %	4.70 %	3.95 %
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 2013, 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 4.5%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans		Other Postretirement Benefit Plans	
	2013	**2012**	**2013**	**2012**
Discount Rate	3.95%	4.55%	3.95%	4.75%
Expected Return on Plan Assets	6.50%	7.25%	7.00%	7.25%
Rate of Compensation Increase	4.50%	4.50%	NA	NA

NA Not applicable.

The expected return on plan assets for 2013 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

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

Health Care Trend Rates	2013	2012
Initial	6.75 %	7.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2020

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

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 164	$ (108)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	2,101	(1,710)

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, 2013, 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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NOTES TO FINANCIAL STATEMENTS (Continued)

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2013 and 2012

The following table provides 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	
	2013	**2012**	**2013**	**2012**
Change in Benefit Obligation	**(in thousands)**			
Benefit Obligation as of January 1,	$ 128,894	$ 121,375	$ 49,370	$ 59,861
Transfer in Mitchell Plant	50,943	-	14,190	-
Service Cost	1,029	1,412	447	1,007
Interest Cost	4,939	5,465	1,832	2,836
Actuarial (Gain) Loss	(9,053)	9,676	(12,855)	5,265
Plan Amendment Prior Service Credit	-	-	-	(16,984)
Benefit Payments	(7,320)	(9,034)	(3,313)	(3,597)
Participant Contributions	-	-	908	784
Medicare Subsidy	-	-	227	198
Benefit Obligation as of December 31,	$ 169,432	$ 128,894	$ 50,806	$ 49,370
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 108,566	$ 100,633	$ 44,834	$ 39,739
Transfer in Mitchell Plant	60,348	-	17,575	-
Actual Gain on Plan Assets	7,984	12,065	2,921	5,626
Company Contributions	-	4,902	-	2,282
Participant Contributions	-	-	908	784
Benefit Payments	(7,320)	(9,034)	(3,313)	(3,597)
Fair Value of Plan Assets as of December 31,	$ 169,578	$ 108,566	$ 62,925	$ 44,834
Funded (Underfunded) Status as of December 31,	$ 146	$ (20,328)	$ 12,119	$ (4,536)

Amounts Recognized on the Balance Sheets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	**2012**	**2013**	**2012**
	(in thousands)			
Special Funds – Prepaid Benefit Costs	$ 146	$ -	$ 11,300	$ -
Accumulated Provision for Pensions and Benefits – Long-term Benefit Liability	-	(20,328)	819	(4,536)
Funded (Underfunded) Status	$ 146	$ (20,328)	$ 12,119	$ (4,536)

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NOTES TO FINANCIAL STATEMENTS (Continued)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
Components	(in thousands)			
Net Actuarial Loss	$ 51,587	$ 47,324	$ 12,769	$ 26,835
Prior Service Cost (Credit)	203	195	(24,069)	(22,306)
Recorded as				
Regulatory Assets	$ 42,089	$ 47,519	$ (9,631)	$ 4,529
Deferred Income Taxes	3,395	-	(584)	-
Net of Tax AOCI	6,306	-	(1,085)	-

Components of the change in amounts included in AOCI and regulatory assets during the years ended December 31, 2013 and 2012 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2013	2012	2013	2012
Components	(in thousands)			
Actuarial (Gain) Loss During the Year	$ 8,734	$ 5,003	$ (12,382)	$ 2,461
Prior Service (Credit) Cost	50	-	(3,784)	(16,984)
Amortization of Actuarial Loss	(4,471)	(3,677)	(1,684)	(1,567)
Amortization of Prior Service Credit (Cost)	(42)	(84)	2,021	504
Change for the Year	$ 4,271	$ 1,242	$ (15,829)	$ (15,586)

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NOTES TO FINANCIAL STATEMENTS (Continued)

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, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 39,294	$ -	$ -	$ -	$ 39,294	23.2 %
International	18,522	-	-	-	18,522	10.9 %
Real Estate Investment Trusts	2,084	-	-	-	2,084	1.2 %
Common Collective Trust - International	-	352	-	-	352	0.2 %
Subtotal - Equities	59,900	352	-	-	60,252	35.5 %
Fixed Income:						
Common Collective Trust - Debt	-	933	-	-	933	0.5 %
United States Government and Agency Securities	-	13,922	-	-	13,922	8.2 %
Corporate Debt	-	57,592	-	-	57,592	34.0 %
Foreign Debt	-	12,372	-	-	12,372	7.3 %
State and Local Government	-	1,007	-	-	1,007	0.6 %
Other - Asset Backed	-	1,198	-	-	1,198	0.7 %
Subtotal - Fixed Income	-	87,024	-	-	87,024	51.3 %
Real Estate	-	-	8,575	-	8,575	5.0 %
Alternative Investments	-	-	11,865	-	11,865	7.0 %
Securities Lending	-	1,266	-	-	1,266	0.8 %
Securities Lending Collateral (a)	-	-	-	(1,627)	(1,627)	(0.9)%
Cash and Cash Equivalents	-	1,749	-	-	1,749	1.0 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	474	474	0.3 %
Total	$ 59,900	$ 90,391	$ 20,440	$ (1,153)	$ 169,578	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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NOTES TO FINANCIAL STATEMENTS (Continued)

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:

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2013	$ 5,076	$ 4,522	$ 9,598
Transfer in Mitchell Plant	3,052	4,222	7,274
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	641	334	975
Relating to Assets Sold During the Period	-	337	337
Purchases and Sales	(194)	2,450	2,256
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2013	$ 8,575	$ 11,865	$ 20,440

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 17,535	$ -	$ -	$ -	$ 17,535	27.9 %
International	22,796	-	-	-	22,796	36.2 %
Common Collective Trust - Global	-	544	-	-	544	0.9 %
Subtotal - Equities	40,331	544	-	-	40,875	65.0 %
Fixed Income:						
Common Collective Trust - Debt	-	3,255	-	-	3,255	5.2 %
United States Government and Agency Securities	-	2,093	-	-	2,093	3.3 %
Corporate Debt	-	4,078	-	-	4,078	6.5 %
Foreign Debt	-	796	-	-	796	1.2 %
State and Local Government	-	171	-	-	171	0.3 %
Other - Asset Backed	-	301	-	-	301	0.5 %
Subtotal - Fixed Income	-	10,694	-	-	10,694	17.0 %
Trust Owned Life Insurance:						
International Equities	-	490	-	-	490	0.8 %
United States Bonds	-	7,836	-	-	7,836	12.4 %
Cash and Cash Equivalents	2,527	325	-	-	2,852	4.5 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	178	178	0.3 %
Total	$ 42,858	$ 19,889	$ -	$ 178	$ 62,925	100.0 %

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

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NOTES TO FINANCIAL STATEMENTS (Continued)

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.

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.

Determination of Pension Expense

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

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

Accumulated Benefit Obligation	December 31, 2013	December 31, 2012
	(in thousands)	
Qualified Pension Plan	$ 166,951	$ 127,325
Total	$ 166,951	$ 127,325

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 were as follows:

	Underfunded Pension Plans 2012
	(in thousands)
Projected Benefit Obligation	$ 128,894
Accumulated Benefit Obligation	$ 127,325
Fair Value of Plan Assets	108,566
Underfunded Accumulated Benefit Obligation	$ (18,759)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the pension plans of $2.7 million during 2014. 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 were capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. 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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NOTES TO FINANCIAL STATEMENTS (Continued)

	Estimated Payments	
	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
2014	$ 10,760	$ 4,508
2015	11,334	4,820
2016	11,489	5,126
2017	11,946	5,385
2018	12,674	5,538
Years 2019 to 2023, in Total	64,896	30,389

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the years ended December 31, 2013 and 2012:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2013	2012	2013	2012
	(in thousands)			
Service Cost	$ 1,029	$ 1,412	$ 447	$ 1,007
Interest Cost	4,939	5,465	1,832	2,836
Expected Return on Plan Assets	(6,419)	(7,392)	(2,949)	(2,911)
Amortization of Prior Service Cost (Credit)	42	84	(2,021)	(504)
Amortization of Net Actuarial Loss	4,471	3,677	1,684	1,567
Net Periodic Benefit Cost (Credit)	4,062	3,246	(1,007)	1,995
Capitalized Portion	(1,767)	(1,438)	438	(884)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 2,295	$ 1,808	$ (569)	$ 1,111

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2014 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 4,335	$ 734
Prior Service Cost (Credit)	55	(2,443)
Total Estimated 2014 Amortization	$ 4,390	$ (1,709)
Expected to be Recorded as		
Regulatory Asset	$ 3,731	$ (1,595)
Deferred Income Taxes	231	(40)
Net of Tax AOCI	428	(74)
Total	$ 4,390	$ (1,709)

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 both 2013 and 2012.

8. BUSINESS SEGMENTS

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

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, 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 extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt 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.

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) 04/11/2014	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of December 31, 2013 and 2012:

Notional Volume of Derivative Instruments

	Volume		
	December 31,		Unit of
Primary Risk Exposure	**2013**	**2012**	**Measure**
	(in thousands)		
Commodity:			
Power	10,071	18,838	MWhs
Coal	2	247	Tons
Natural Gas	509	2,018	MMBtus
Heating Oil and Gasoline	261	269	Gallons
Interest Rate	$ 2,615	$ 4,836	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, 2013 and 2012 balance sheets, KPCo netted $0 and $253 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $1 million and $2.2 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, 2013 and 2012:

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	Commodity (a)	Commodity (a)	Interest Rate (a)			
			(in thousands)			
Derivative Instrument Assets	$ 13,826	$ -	$ -	$ 13,826	$ (6,065)	$ 7,761
Long-Term Portion of Derivative Instrument Assets	4,306	-	-	4,306	(822)	3,484
Derivative Instrument Assets – Hedges	-	85	-	85	(6)	79
Derivative Instrument Liabilities	10,553	-	-	10,553	(6,679)	3,874
Long-Term Portion of Derivative Instrument Liabilities	2,970	-	-	2,970	(865)	2,105
Derivative Instrument Liabilities – Hedges	-	65	-	65	(6)	59

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
	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

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

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

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

The table below presents KPCo's activity of derivative risk management contracts for the years ended December 31, 2013 and 2012:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

	Years Ended December 31,	
Location of Gain (Loss)	**2013**	**2012**
	(in thousands)	
Operating Revenues	$ 1,483	$ (1,597)
Regulatory Liabilities (a)	(1,029)	1,047
Total Gain (Loss) on Risk Management Contracts	$ 454	$ (550)

(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 revenues on a net basis on KPCo's statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's statements of income depending on the relevant facts and circumstances. 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 the statements of income. During 2013 and 2012, 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 2013 and 2012, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income on its balance sheets into Operation Expenses, Maintenance Expenses or Depreciation Expense, as it relates to capital projects, on the statements of income. During 2013 and 2012, 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 2013 and 2012, 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 designated as the hedged items in qualifying foreign currency hedging relationships. During 2013 and 2012, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During 2013 and 2012, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets and the reasons for changes in cash flow hedges, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income on the balance sheets as of December 31, 2013 and 2012 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 79	$ -	$ 79
Hedging Liabilities (a)	59	-	59
AOCI Gain (Loss) Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

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

	Commodity	Interest Rate	Total
		(in thousands)	
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)

(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, 2013, 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 was 12 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (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, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 118	$ 432
Amount of Collateral KPCo Would Have Been Required to Post	565	741
Amount Attributable to RTO and ISO Activities	522	703

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, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 4,039	$ 9,907
Amount of Cash Collateral Posted	-	365
Additional Settlement Liability if Cross Default Provision is Triggered	3,817	6,041

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

The book values and fair values of Long-term Debt as of December 31, 2013 and 2012 are summarized in the following table:

	December 31,			
	2013		2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 749,389	$ 841,594	$ 549,222	$ 708,566

Fair Value Measurements of Financial Assets and Liabilities

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

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012. 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.

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Kentucky Power Company	(1) X An Original (2) _ A Resubmission	04/11/2014	2013/Q4

NOTES TO FINANCIAL STATEMENTS (Continued)

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

Assets:	**Level 1**	**Level 2**	**Level 3**	**Other**	**Total**
			(in thousands)		
Derivative Instrument Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Derivative Instrument Assets – Hedges					
Cash Flow Hedges – Commodity (a)	-	85	-	(6)	79
Total Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Derivative Instrument Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Derivative Instrument Liabilities – Hedges					
Cash Flow Hedges – Commodity (a)	-	65	-	(6)	59
Total Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

Assets:	**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

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

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2013 and 2012.

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, 2013	**Net Risk Management Assets (Liabilities) (in thousands)**
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(732)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	101
Transfers into Level 3 (d) (e)	273
Transfers out of Level 3 (e) (f)	(187)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	517
Balance as of December 31, 2013	$ 2,171

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

(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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NOTES TO FINANCIAL STATEMENTS (Continued)

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2013 and 2012:

Significant Unobservable Inputs
December 31, 2013

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

Significant Unobservable Inputs
December 31, 2012

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range 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.

11. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2013	2012
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 5,239	$ 13,342
Deferred		
Deferred Investment Tax Credits	17,134	10,184
	(230)	(278)
Total	22,143	23,248
Charged (Credited) to Nonoperating Income, Net:		
Current	684	(742)
Deferred	(12,689)	(104)
Total	(12,005)	(846)
Income Tax Expense	$ 10,138	$ 22,402

Name of Respondent	This Report is:	Date of Report	Year/Period of Report
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NOTES TO FINANCIAL STATEMENTS (Continued)

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

	Years Ended December 31, 2013	2012
	(in thousands)	
Net Income	$ 13,872	$ 50,978
Income Tax Expense	10,138	22,402
Pretax Income	$ 24,010	$ 73,380
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 8,404	$ 25,683
Increase (Decrease) in Income Taxes resulting from the following items:		
Depreciation	2,648	2,382
AFUDC	(749)	(894)
Removal Costs	(2,475)	(3,885)
Investment Tax Credits, Net	(230)	(278)
State and Local Income Taxes, Net	1,626	1,516
Parent Company Loss Benefit	(293)	(1,292)
Other	1,207	(830)
Income Tax Expense	$ 10,138	$ 22,402
Effective Income Tax Rate	42.2%	30.5%

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

	December 31, 2013	2012
	(in thousands)	
Deferred Tax Assets	$ 56,348	$ 28,380
Deferred Tax Liabilities	(613,126)	(385,153)
Net Deferred Tax Liabilities	$ (556,778)	$ (356,773)
Property Related Temporary Differences	$ (437,346)	$ (271,200)
Amounts Due from Customers for Future Federal Income Taxes	(29,842)	(29,800)
Deferred State Income Taxes	(80,444)	(42,345)
Deferred Income Taxes on Other Comprehensive Loss	2,918	220
Regulatory Assets	(17,063)	(20,604)
All Other, Net	4,999	6,956
Net Deferred Tax Liabilities	$ (556,778)	$ (356,773)

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NOTES TO FINANCIAL STATEMENTS (Continued)

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

KPCo and other AEP subsidiaries file income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns. KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income.

Tax Credit Carryforward

Federal net income tax operating losses sustained in 2011 and 2009, along with lower federal taxable income in 2010, resulted in unused federal income tax credits. As of December 31, 2013, KPCo had federal general business tax credit carryforwards of $232 thousand. If these credits are not utilized, $218 thousand of federal general business tax credits will expire in the years 2029 through 2032.

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

Uncertain Tax Positions

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

The following table shows amounts reported for interest expense and interest income:

	Years Ended December 31, 2013	2012
	(in thousands)	
Interest Expense	$ -	$ 23
Interest Income	99	-

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

	December 31, 2013	December 31, 2012
	(in thousands)	
Accrual for Receipt of Interest	$ 1	$ 1
Accrual for Payment of Interest and Penalties	98	92

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

	2013	2012
	(in thousands)	
Balance as of January 1,	$ 1,333	$ 1,608
Increase - Tax Positions Taken During a Prior Period	-	-
Decrease - Tax Positions Taken During a Prior Period	(725)	(93)
Increase - Tax Positions Taken During the Current Year	-	-
Decrease - Tax Positions Taken During the Current Year	-	-
Decrease - Settlements with Taxing Authorities	-	(182)
Decrease - Lapse of the Applicable Statute of Limitations	-	-
Balance as of December 31,	$ 608	$ 1,333

There are no unrecognized tax benefits that affected the effective tax rate for 2013 and 2012. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The 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 did not materially impact KPCo's net income or financial condition but had a favorable impact on cash flows in 2013.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to KPCo's net income, cash flows or financial condition.

State Tax Legislation

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

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

12. LEASES

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

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

Lease Rental Costs	Years Ended December 31, 2013	2012
	(in thousands)	
Net Lease Expense on Operating Leases	$ 1,379	$ 1,133
Amortization of Capital Leases	1,471	1,442
Interest on Capital Leases	251	242
Total Lease Rental Costs	$ 3,101	$ 2,817

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

	December 31, 2013	2012
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 2,854	$ 683
Other Property, Plant and Equipment	3,425	4,500
Total Property, Plant and Equipment Under Capital Leases	6,279	5,183
Accumulated Amortization	1,869	2,105
Net Property, Plant and Equipment Under Capital Leases	$ 4,410	$ 3,078
Obligations Under Capital Leases		
Noncurrent	$ 3,420	$ 1,674
Current	990	1,404
Total Obligations Under Capital Leases	$ 4,410	$ 3,078

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Future minimum lease payments consisted of the following as of December 31, 2013:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2014	$ 1,147	$ 1,324
2015	1,025	1,153
2016	812	1,091
2017	672	923
2018	471	629
Later Years	851	1,493
Total Future Minimum Lease Payments	4,978	$ 6,613
Less Estimated Interest Element	568	
Estimated Present Value of Future Minimum Lease Payments	$ 4,410	

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, 2013, the maximum potential loss for these lease agreements was approximately $1.1 million assuming the fair value of the equipment is zero at the end of the lease term.

13. 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, 2013 and 2012:

Type of Debt	Maturity	Weighted Average Interest rate as of December 31, 2013	Interest Rate Ranges as of December 31, 2013	2012	Outstanding as of December 31, 2013	2012
					(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
Other Long-term Debt (a)	2015	1.188%	1.188%		200,000	-
Unamortized Discount, Net					(611)	(778)
Total Long-term Debt Outstanding					$ 749,389	$ 549,222

(a) In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. In 2013, OPCo borrowed $1 billion under the credit facility and retired other certain debt. On December 31, 2013, OPCo assigned the $1 billion in credit facility borrowings to AGR upon the transfer of OPCo's generation assets to AGR. Also on December 31, 2013, AGR subsequently assigned a portion of the borrowings to KPCo in the amount of $200 million upon AGR's transfer of certain of those generation assets.

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Long-term debt outstanding as of December 31, 2013 is payable as follows:

	2014	2015	2016	2017	2018	After 2018	Total
				(in thousands)			
Principal Amount	$ -	$ 220,000	$ -	$ 325,000	$ -	$ 205,000	$ 750,000
Unamortized Discount, Net							(611)
Total Long-term Debt Outstanding							$ 749,389

Dividend Restrictions

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

Federal Power Act

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

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. As of December 31, 2013, none of KPCo's retained earnings have restrictions related to the payment of dividends to Parent.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2013 and 2012 are included in Notes Payable to Associated Companies on the balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2013 and 2012 are described in the following table:

Year	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2013	$ 32,649	$ 31,421	$ 10,911	$ 14,584	$ 8,564	$ 250,000
2012	13,359	80,205	9,200	46,187	13,359	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, 2013 and 2012 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2013	0.43 %	0.29 %	0.41 %	0.24 %	0.37 %	0.32 %
2012	0.42 %	0.42 %	0.56 %	0.39 %	0.42 %	0.48 %

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 for the years ended December 31, 2013 and 2012:

	Years Ended December 31, 2013	2012
	(in thousands)	
Interest Expense	$ 12	$ 1
Interest Income	36	222

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 June 2013, AEP Credit amended its receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. AEP Credit amended a commitment of $385 million to now expire in June 2014. The remaining commitment of $315 million expires in June 2015. AEP Credit intends to extend or replace the agreement expiring in June 2014 on or before its maturity.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $43 million and $46 million as of December 31, 2013 and 2012, 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, 2013 and 2012.

KPCo's proceeds on the sale of receivables to AEP Credit were $522 million and $517 million for the years ended December 31, 2013 and 2012, respectively.

14. RELATED PARTY TRANSACTIONS

For other related party transactions, also see “AEP System Tax Allocation Agreement” section of Note 11 in addition to “Utility Money Pool – AEP System” and “Sale of Receivables – AEP Credit” sections of Note 13.

Interconnection Agreement

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

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

Effective January 1, 2014, the FERC approved the creation of the Power Coordination Agreement among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants’ respective power supply resources. Also effective January 1, 2014, the FERC approved the Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM. See “Corporate Separation and Termination of Interconnection Agreement” section of Note 3.

Prior to January 1, 2014, power, natural gas and risk management activities were conducted by AEPSC and profits and losses were allocated under the SIA to members of the Interconnection Agreement, PSO and SWEPCo. Risk management activities involved the purchase and sale of power and natural gas under physical forward contracts at fixed and variable prices. In addition, the risk management of power, and to a lesser extent natural gas contracts, included exchange traded futures and options and OTC options and swaps. The majority of these transactions represented physical forward contracts in the AEP System’s traditional marketing area and were typically settled by entering into offsetting contracts. In addition, AEPSC entered into transactions for the purchase and sale of power and natural gas options, futures and swaps, and for the forward purchase and sale of power outside of the AEP System’s traditional marketing area.

Operating Agreement

PSO, SWEPCo and AEPSC are parties to the Operating Agreement which was approved by the FERC. The Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. 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 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 (prior to January 1, 2014) and the 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 the 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 the 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.

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales under the Interconnection Agreement, direct sales to affiliates, net transmission agreement sales and other revenues for the years ended December 31, 2013 and 2012:

Related Party Revenues	Years Ended December 31, 2013	2012
	(in thousands)	
Sales under Interconnection Agreement	$ 43,496	$ 32,513
Direct Sales to West Affiliates	119	64
Transmission Agreement Sales	862	3,022
Other Revenues	262	270

The following table shows the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2013 and 2012:

Related Party Purchases	Years Ended December 31, 2013	2012
	(in thousands)	
Purchases under Interconnection Agreement	$ 167,701	$ 125,726
Direct Purchases from West Affiliates	1	11
Purchases from AEGCo	107,794	102,371

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, KGPCo, KPCo, OPCo and WPCo are parties to the TA, effective November 2010, which defines how transmission costs through PJM OATT are allocated among the AEP East Companies, KGPCo and WPCo on a 12-month average coincident peak basis. KPCo's net charges recorded as a result of the TA for the years ended December 31, 2013 and 2012 were $3 million and $1.1 million, 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 natural 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 natural 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 natural gas managed by AEPES were $124 thousand and $173 thousand for the years ended December 31, 2013 and 2012, respectively. These purchases are reflected 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 $50 thousand and $74 thousand in 2013 and 2012, 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 $687 thousand and $277 thousand for the years ended December 31, 2013 and 2012, 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:

	December 31,	
Billing Company	**2013**	**2012**
	(in thousands)	
AGR	$ (20)	$ -
APCo	26	98
OPCo	-	41

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, sales and purchases of meters and transformers, and sales and purchases of transmission property. There were no gains or losses recorded on the transactions. The following table shows the sales and purchases, recorded at net book value in Utility Plant, for the years ended December 31, 2013 and 2012:

	Years Ended December 31,	
	2013	**2012**
	(in thousands)	
Sales	$ 166	$ 657
Purchases	1,702	601

Global Borrowing Notes

As of December 31, 2013 and 2012, 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, 2013 and 2012 were $33 million and $35 million, respectively.

15. PROPERTY, PLANT AND EQUIPMENT

Depreciation

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

Year	Steam	Transmission	Distribution	General
		(in percentages)		
2013	3.7	1.8	3.4	4.3
2012	3.8	1.6	3.4	7.2

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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NOTES TO FINANCIAL STATEMENTS (Continued)

The following is a reconciliation of the 2013 and 2012 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)			
2013	$ 3,902	$ 339	$ -	$ (136)	$ 16,421	$ 20,526
2012	3,772	320	-	(190)	-	3,902

Jointly-owned Electric Facilities

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

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2013					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 907,304	$ 75,253	$ 305,170

(a) Operated by KPCo.

16. 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 facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was 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 of $1.7 million in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of December 31, 2013
		(in thousands)			
$ 497	$ 166	$ -	$ (262)	$ (401)	$ -

These expenses, net of adjustments, relate primarily to severance benefits. Management does not expect additional costs to be incurred related to this initiative.

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				(5,220,773)
8	Current Quarter/Year to Date Changes in Fair Value				
9	Total (lines 7 and 8)				(5,220,773)
10	Balance of Account 219 at End of Current Quarter/Year				(5,220,773)

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

Line No.	Other Cash Flow Hedges Interest Rate Swaps (f)	Other Cash Flow Hedges [Specify] (g)	Totals for each category of items recorded in Account 219 (h)	Net Income (Carried Forward from Page 117, Line 78) (i)	Total Comprehensive Income (j)
1	(342,389)	(282,855)	(625,244)		
2	60,422	402,135	462,557		
3		(246,193)	(246,193)		
4	60,422	155,942	216,364	50,978,453	51,194,817
5	(281,967)	(126,913)	(408,880)		
6	(281,967)	(126,913)	(408,880)		
7	60,422	(2,642)	(5,162,993)		
8		152,171	152,171		
9	60,422	149,529	(5,010,822)	13,872,009	8,861,187
10	(221,545)	22,616	(5,419,702)		

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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 122(a)(b) Line No.: 7 Column: e

Pension and OPEB Adjustment Related to Mitchell Plant transferred to KPCo on 12/31/2013.

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	04/11/2014	End of 2013/Q4

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

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

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	2,643,823,159	2,643,823,159
4	Property Under Capital Leases	4,409,682	4,409,682
5	Plant Purchased or Sold		
6	Completed Construction not Classified	71,803,255	71,803,255
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	2,720,036,096	2,720,036,096
9	Leased to Others		
10	Held for Future Use	7,405,959	7,405,959
11	Construction Work in Progress	128,599,148	128,599,148
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	2,856,041,203	2,856,041,203
14	Accum Prov for Depr, Amort, & Depl	961,039,344	961,039,344
15	Net Utility Plant (13 less 14)	1,895,001,859	1,895,001,859
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	941,819,616	941,819,616
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	19,219,728	19,219,728
22	Total In Service (18 thru 21)	961,039,344	961,039,344
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)	961,039,344	961,039,344

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	04/11/2014	End of 2013/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
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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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 200 Line No.: 15 Column: c

Per FERC Docket #EC13-28-000 transfer 50% ownership of Mitchell Plant to Kentucky Power Co. effective 12/31/13

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	04/11/2014	End of 2013/Q4

NUCLEAR FUEL MATERIALS (Account 120.1 through 120.6 and 157)

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

Line No.	Description of item (a)	Balance Beginning of Year (b)	Changes during Year Additions (c)
1	Nuclear Fuel in process of Refinement, Conv, Enrichment & Fab (120.1)		
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)		

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
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			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	04/11/2014	End of 2013/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	17,681,117	3,160,277
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	17,734,036	3,160,277
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,076,546	677,393
9	(311) Structures and Improvements	43,159,343	126,865
10	(312) Boiler Plant Equipment	368,901,994	3,471,241
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	110,300,662	820,956
13	(315) Accessory Electric Equipment	16,390,875	131,333
14	(316) Misc. Power Plant Equipment	8,029,252	693,916
15	(317) Asset Retirement Costs for Steam Production	3,614,563	
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	551,473,235	5,921,704
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)	551,473,235	5,921,704

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	04/11/2014	End of 2013/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	29,262,471	702,311
49	(352) Structures and Improvements	6,596,339	46,524
50	(353) Station Equipment	169,157,602	6,383,701
51	(354) Towers and Fixtures	94,468,956	48,587
52	(355) Poles and Fixtures	70,056,522	4,692,815
53	(356) Overhead Conductors and Devices	120,461,944	2,082,173
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)	490,121,490	13,956,111
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	7,179,509	314,620
61	(361) Structures and Improvements	4,381,430	
62	(362) Station Equipment	76,399,914	8,356,320
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	173,978,664	7,565,035
65	(365) Overhead Conductors and Devices	164,605,796	17,809,128
66	(366) Underground Conduit	5,797,157	581,754
67	(367) Underground Conductors and Devices	8,915,361	962,674
68	(368) Line Transformers	113,943,852	6,160,924
69	(369) Services	49,819,404	4,416,304
70	(370) Meters	24,731,169	858,140
71	(371) Installations on Customer Premises	19,061,691	2,189,522
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	3,173,779	244,002
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	651,987,726	49,458,423
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	20,722,927	550,259
88	(391) Office Furniture and Equipment	1,279,644	403,689
89	(392) Transportation Equipment	14,768	
90	(393) Stores Equipment	159,895	4,653
91	(394) Tools, Shop and Garage Equipment	3,395,435	158,260
92	(395) Laboratory Equipment	141,764	
93	(396) Power Operated Equipment	5,931	
94	(397) Communication Equipment	6,855,599	849,587
95	(398) Miscellaneous Equipment	1,035,595	31,844
96	SUBTOTAL (Enter Total of lines 86 thru 95)	35,136,289	1,998,292
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)	35,217,344	1,998,292
100	TOTAL (Accounts 101 and 106)	1,746,533,831	74,494,807
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)	1,746,533,831	74,494,807

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
5,357,017	252,893		15,737,270		4
5,357,017	252,893		15,790,189		5
					6
					7
	604,590		2,358,529		8
-5,457	42,000,197		85,291,862		9
1,769,543	773,835,099		1,144,438,791		10
					11
1,598,668	53,295,697		162,818,647		12
9,007	17,080,672		33,593,873		13
13,990	7,693,412		16,402,590		14
	12,794,122		16,408,685		15
3,385,751	907,303,789		1,461,312,977		16
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3,385,751	907,303,789		1,461,312,977		46

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
			29,964,782		48
6,195	72,117		6,708,785		49
4,697,632	9,512,983		180,356,654		50
			94,517,543		51
52,617			74,696,720		52
6,209			122,537,908		53
			11,590		54
			106,066		55
					56
					57
4,762,653	9,585,100		508,900,048		58
					59
			7,494,129		60
9,424			4,372,006		61
1,091,672			83,664,562		62
					63
972,449		-19,918	180,551,332		64
2,908,748		32,545	179,538,721		65
1,819			6,377,092		66
65,079			9,812,956		67
1,079,231		-12,627	119,012,918		68
335,346			53,900,362		69
866,023			24,723,286		70
1,194,663			20,056,550		71
					72
68,439			3,349,342		73
					74
8,592,893			692,853,256		75
					76
					77
					78
					79
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					81
					82
					83
					84
					85
			1,524,731		86
57,639			21,215,547		87
			1,683,333		88
			14,768		89
			164,548		90
			3,553,695		91
			141,764		92
			5,931		93
386,231			7,318,955		94
1,822			1,065,617		95
445,692			36,688,889		96
					97
			81,055		98
445,692			36,769,944		99
22,544,006	917,141,782		2,715,626,414		100
					101
					102
					103
22,544,006	917,141,782		2,715,626,414		104

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	04/11/2014	2013/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.

Schedule Page: 204 Line No.: 104 Column: e

Per FERC Docket #EC13-28-000 transfer 50% ownership of Mitchell Plant to Kentucky Power Co. effective 12/31/13

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	04/11/2014	End of 2013/Q4

ELECTRIC PLANT LEASED TO OTHERS (Account 104)

Line No.	Name of Lessee (Designate associated companies with a double asterisk) (a)	Description of Property Leased (b)	Commission Authorization (c)	Expiration Date of Lease (d)	Balance at End of Year (e)
1					
2					
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44					
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	04/11/2014	End of 2013/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Carrs Site (8500)	8/17/82		6,778,355
3				
4	Ramey Substation (4205)	10/1/09	2014	627,604
5				
6				
7				
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21	Other Property:			
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46				
47	Total			7,405,959

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	04/11/2014	2013/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	04/11/2014	End of 2013/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	BS2 HP R/H & 2nd R/H	2,207,738
2	ML U1&2 Dry Fly Ash Conversion	48,368,324
3	KP/Jeff Sta - Add 69-34.5 kV	3,063,880
4	ML New Landfill	13,735,931
5	ML New Landfill Haul Road	8,222,984
6	KP/VoltVar Circ Reconfig DLine	2,461,512
7	DS/KYPCO/Replace &Refurbish	1,112,402
8	TS/KyP/Bonnyman Sta removal	5,632,165
9	T/KY/Line: Conxt: Bonnyman-Sof	22,084,110
10	TL/KYPCO/Fleming to Jenkins	1,062,716
11	ML0-Conners Run Expansion	3,934,255
12	WS-CI-KEPCo-G PPB	2,118,585
13	ET-CI-KEPCo-T ASSET IMP	2,247,019
14	Ed-Ci-Kepco-D Ast Imp	1,055,181
15	Other Minor Projects Under $1,000,000	11,292,346
16		
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42		
43	TOTAL	128,599,148

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	04/11/2014	2013/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.

Schedule Page: 216 Line No.: 15 Column: b

Per FERC Docket #EC-13-28-000 transfer 50% ownership of Mitchell Plant to Kentucky Power Co. effective 12/31/13

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	04/11/2014	End of 2013/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	601,239,741	601,239,741		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	53,720,815	53,720,815		
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):	195,254	195,254		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	53,916,069	53,916,069		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	17,184,603	17,184,603		
13	Cost of Removal	8,349,011	8,349,011		
14	Salvage (Credit)	2,644,058	2,644,058		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	22,889,556	22,889,556		
16	Other Debit or Cr. Items (Describe, details in footnote):	309,553,362	309,553,362		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	941,819,616	941,819,616		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	586,600,561	586,600,561		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	162,742,412	162,742,412		
26	Distribution	184,127,054	184,127,054		
27	Regional Transmission and Market Operation				
28	General	8,349,589	8,349,589		
29	TOTAL (Enter Total of lines 20 thru 28)	941,819,616	941,819,616		

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	04/11/2014	2013/Q4

FOOTNOTE DATA

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

Asbestos ARO depreciation expense in account 1080013 $195,254

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

Includes $2,332,633 of removal cost in retirement work in progress (RWIP).

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

Includes $(339,061) of salvage charges in retirement work in progress (RWIP).

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

Asbestos ARO reserve in account 1080013	$	(533,586)
Per FERC Docket #EC13-28-000 transfer 50% ownership of Mitchell Plant to Kentucky Power Co effective 12/31/13	$	310,086,948
Total	$	309,553,362

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	04/11/2014	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

INVESTMENTS IN SUBSIDIARY COMPANIES (Account 123.1) (Continued)

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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)	67,280,320	88,640,523	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	1,866,856	3,672,774	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	4,066,629	5,934,567	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	8,496,249	16,986,675	Electric
8	Transmission Plant (Estimated)	29,645	73,844	Electric
9	Distribution Plant (Estimated)	309,165	159,945	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	6,628	19,298	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	12,908,316	23,174,329	
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)	82,055,492	115,487,626	

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	04/11/2014	2013/Q4

FOOTNOTE DATA

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

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

Schedule Page: 227 Line No.: 20 Column: c

Per FERC Docket #EC13-28-000 transfer 50% ownership of Mitchell Plant to Kentucky Power Co. effective 12/31/13

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	04/11/2014	End of 2013/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)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	123,089.00	12,124,691	46,563.00	2,361,231
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)				
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Appalachian Power Company	4,510.00	1,585,761		
10	Ohio Power Company	69,095.00	9,379,542	23,634.00	1,019,135
11					
12					
13					
14					
15	Total	73,605.00	10,965,303	23,634.00	1,019,135
16					
17	Relinquished During Year:				
18	Charges to Account 509	51,228.00	5,788,988		
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	AEP System Pool	930.00	139,825		
23					
24					
25					
26					
27					
28	Total	930.00	139,825		
29	Balance-End of Year	144,536.00	17,161,181	70,197.00	3,380,366
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	505.00		362.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	505.00			
40	Balance-End of Year			362.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		142		
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	04/11/2014	End of 2013/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.

2015 No. (f)	2015 Amt. (g)	2016 No. (h)	2016 Amt. (i)	Future Years No. (j)	Future Years Amt. (k)	Totals No. (l)	Totals Amt. (m)	Line No.
34,754.00		34,754.00		904,386.00		1,143,546.00	14,485,922	1
								2
								3
				34,945.00		34,945.00		4
								5
								6
								7
								8
						4,510.00	1,585,761	9
19,325.00		19,326.00		521,789.00		653,169.00	10,398,677	10
								11
								12
								13
								14
19,325.00		19,326.00		521,789.00		657,679.00	11,984,438	15
								16
								17
						51,228.00	5,788,988	18
								19
								20
								21
						930.00	139,825	22
								23
								24
								25
								26
								27
						930.00	139,825	28
54,079.00		54,080.00		1,461,120.00		1,784,012.00	20,541,547	29
								30
								31
								32
								33
								34
								35
362.00		362.00		24,244.00		25,835.00		36
				723.00		723.00		37
								38
				361.00		866.00		39
362.00		362.00		24,606.00		25,692.00		40
								41
								42
								43
					22		164	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	04/11/2014	End of 2013/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)	2014 No. (d)	2014 Amt. (e)
1	Balance-Beginning of Year	13,111.00	28,274	10,610.00	
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	135.00			
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Ohio Power Company	1,140.00	221,509	4,282.00	
10					
11					
12					
13					
14					
15	Total	1,140.00	221,509	4,282.00	
16					
17	Relinquished During Year:				
18	Charges to Account 509	7,371.00	14,461	364.00	
19	Other:				
20					
21	Cost of Sales/Transfers:				
22	Louisville Gas & Elec Co.	420.00	1,291		
23	DTE Electric Company	500.00	1,858		
24	Homer City Generation LP	1,000.00	3,655		
25	Kentucky Utilities Co.	330.00	1,015		
26	MidAmerican Energy Co.	810.00	2,489		
27	Other	1,453.00	539		
28	Total	4,513.00	10,847		
29	Balance-End of Year	2,502.00	224,475	14,528.00	
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)				
33	Net Sales Proceeds (Other)		151,411		
34	Gains		140,564		
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	04/11/2014	End of 2013/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.

2015		2016		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
						23,721.00	28,274	1
								2
								3
						135.00		4
								5
								6
								7
								8
						5,422.00	221,509	9
								10
								11
								12
								13
								14
						5,422.00	221,509	15
								16
								17
						7,735.00	14,461	18
								19
								20
								21
						420.00	1,291	22
						500.00	1,858	23
						1,000.00	3,655	24
						330.00	1,015	25
						810.00	2,489	26
						1,453.00	539	27
						4,513.00	10,847	28
						17,030.00	224,475	29
								30
								31
								32
							151,411	33
							140,564	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	04/11/2014	End of 2013/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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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)]	Total Amount of Charges	Costs Recognised During Year	WRITTEN OFF DURING YEAR		Balance at End of Year
				Account Charged	Amount	
	(a)	(b)	(c)	(d)	(e)	(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	04/11/2014	End of 2013/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2	PJM - #Y2-045 Baker	662	186	(662)	186
3	345KV Feasibility Study				
4					
5	PJM - #Y2-045 Baker	38	186	(38)	186
6	345KV Impact Study				
7					
8	PJM - #Y2-086 Engle	61,221	186	(61,221)	186
9	69KV Feasibility Study				
10					
11	PJM - #Y2-086 Engle	966	186	(966)	186
12	69KV Impact Study				
13					
14					
15					
16					
17					
18					
19					
20					
21	**Generation Studies**				
22	None				
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	11,746,110		593	4,698,444	7,047,666
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	86,311,032	14,464,355	Various	14,514,241	86,261,146
8						
9	SFAS 109 Deferred SIT	42,344,691	29,918,678	Various	2,923,982	69,339,387
10						
11	Post In-Service AFUDC Hanging Rock/	665,640		406	33,408	632,232
12	Jefferson 765 KV Line					
13	Amortz period: Dec 1984 - Nov 2032					
14						
15	Depreciation Expense - Hanging Rock/	103,729		406	5,208	98,521
16	Jefferson 765 KV Line					
17	Amortz period: Dec 1984 - Nov 2032					
18						
19	Deferred DSM Expense	1,589,323	4,692,898	456, 908	5,368,465	913,756
20						
21	Deferred Carbon Management Research	175,010	250,000	188, 506	299,996	125,014
22	Kentucky PSC Case 2008-00308 & 2009-00459					
23	Amortz period: July 2010 - June 2018					
24						
25	Deferred Equity Carrying Charge	(107,685)	22,428	407	111	-85,368
26						
27	BridgeCo Transmission Org Funding	265,003		407, 421	44,111	220,892
28	Amortz period: Jan 2005 - Dec 2019					
29	FERC Docket AC04-101-000					
30						
31	PJM Integration Payments	274,003		407, 421	132,204	141,799
32	Amortz period: Jan 2005 - Dec 2014					
33	FERC Docket EL05-74-000					
34						
35	Other PJM Integration	279,976		407, 421	46,603	233,373
36	Amortz period: Jan 2005 - Dec 2019					
37	FERC Docket AC04-101-000					
38						
39	Carrying Charges - RTO Startup Costs	148,357	119,447	407, 421	108,107	159,697
40	Amortz period: Jan 2005 - Dec 2019					
41	FERC Docket AC04-101-000					
42						
43						
44	TOTAL	214,230,662	110,962,425		108,472,379	216,720,708

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	04/11/2014	End of 2013/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	138,700		407, 421	23,087	115,613
2	Amortz period: Jan 2005 - Dec 2019					
3	FERC Docket AC04-101-000					
4						
5	SFAS 112 Post Employment Benefit	5,229,713	2,623,080	Various	3,323,024	4,529,769
6						
7	SFAS 158 Employers' Accounting for Defined	52,048,201	40,938,845	Various	60,528,936	32,458,110
8	Benefit Pension and Other Postretirement Plans					
9						
10	Unrealized Loss on Forward Commitments		12,625,503	Various	12,625,222	281
11						
12	Carbon Capture FEED Study	872,859		426	872,859	
13						
14	SFAS 106 Medicare Subsidy		5,307,191	926	2,924,371	2,382,820
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44	TOTAL	214,230,662	110,962,425		108,472,379	216,720,708

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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 232 Line No.: 9 Column: c

Amount includes Regulatory Assets associated with the Mitchell Plant transfer at 12/31/2013.

Schedule Page: 232.1 Line No.: 7 Column: c

Amount includes Regulatory Assets associated with the Mitchell Plant transfer at 12/31/2013.

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	04/11/2014	End of 2013/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	10,424,709	17,958,814	408	13,407,683	14,975,840
2						
3	Liquidated Rail Damages	2,750,000		232, 253	2,750,000	
4						
5	Agency Fees - Factored A/R	910,519	10,700,901	Various	10,745,286	866,134
6						
7	Unamortized Credit Line Fees	542,150	569,191	431	211,399	899,942
8	Amortized thru July 2017					
9						
10	Deferred Lease Assets	201,683	587,827	Various	300,667	488,843
11						
12	Miscellaneous Items	482	27,483	Various	27,543	422
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47	Misc. Work in Progress	184,204				341,782
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	15,013,747				17,572,963

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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 233 Line No.: 1 Column: c

Amount includes Deferred Debits associated with the Mitchell Plant transfer at 12/31/2013.

Schedule Page: 233 Line No.: 7 Column: c

Amount includes Deferred Debits associated with the Mitchell Plant transfer at 12/31/2013.

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	04/11/2014	End of 2013/Q4

ACCUMULATED DEFERRED INCOME TAXES (Account 190)

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

Line No.	Description and Location (a)	Balance of Begining of Year (b)	Balance at End of Year (c)
1	Electric		
2	Interest Expense Capitalized	6,454,725	6,753,194
3	Contribution-In-Aid Of Construction	2,181,725	1,946,590
4	Deferred Fuel	7,110,307	4,548,634
5	Pension	-7,867,069	-6,799,943
6	SFAS 106 Post Retirement Expenses	3,199,428	2,117,922
7	Other	2,640,297	19,299,637
8	TOTAL Electric (Enter Total of lines 2 thru 7)	13,719,413	27,866,034
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	14,660,289	28,481,502
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	28,379,702	56,347,536

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	04/11/2014	2013/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	753,067	874,612
SFAS 109	13,663,909	24,655,788
SFAS 133	243,313	139,917
SFAS 87	0	2,811,185
	14,660,289	28,481,502

Summary:

1901001	Accum DFIT - Other	27,866,034
1902001	Accum DFIT - Other Income & Deductions	874,612
1903001	Accum DFIT - SFAS 109 Flow-Thru	24,330,351
1904001	Accum DFIT - SFAS 109 Excess	325,437
	SubTotal A/C 190	53,396,434
1900006	SFAS 133 Non-Affil Fed Accum DFIT	20,623
1900009	SFAS 87 ADIT Federal - Pension OCI	2,811,185
1900015	ADIT-Fed-Hdg-CF-Int Rate	119,294
	TOTAL A/C 190	56,347,536

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	04/11/2014	End of 2013/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				
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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	04/11/2014	End of 2013/Q4

CAPITAL STOCKS (Account 201 and 204) (Continued)

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

OUTSTANDING PER BALANCE SHEET (Total amount outstanding without reduction for amounts held by respondent)		HELD BY RESPONDENT				Line No.
		AS REACQUIRED STOCK (Account 217)		IN SINKING AND OTHER FUNDS		
Shares (e)	Amount (f)	Shares (g)	Cost (h)	Shares (i)	Amount (j)	
1,009,000	50,450,000					1
						2
						3
						4
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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	04/11/2014	End of 2013/Q4

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

Report below the balance at the end of the year and the information specified below for the respective other paid-in capital accounts. Provide a subheading for each account and show a total for the account, as well as total of all accounts for reconciliation with balance sheet, Page 112. Add more columns for any account if deemed necessary. Explain changes made in any account during the year and give the accounting entries effecting such change.
(a) Donations Received from Stockholders (Account 208)-State amount and give brief explanation of the origin and purpose of each donation.
(b) Reduction in Par or Stated value of Capital Stock (Account 209): State amount and give brief explanation of the capital change which gave rise to amounts reported under this caption including identification with the class and series of stock to which related.
(c) Gain on Resale or Cancellation of Reacquired Capital Stock (Account 210): Report balance at beginning of year, credits, debits, and balance at end of year with a designation of the nature of each credit and debit identified by the class and series of stock to which related.
(d) Miscellaneous Paid-in Capital (Account 211)-Classify amounts included in this account according to captions which, together with brief explanations, disclose the general nature of the transactions which gave rise to the reported amounts.

Line No.	Item (a)	Amount (b)
1	Account 208 - Donations Received From Stockholders	
2	Contributions by Parent Company prior to 2013	238,750,000
3	Contributions from plant transfer in 2013	375,898,268
4		
5	Subtotal - Account 208	614,648,268
6		
7	Account 209 - Reduction in Par or Stated Value of Capital Stock	
8		
9	Account 210 - Gain on Resale/Cancellation of Reacquired Capital Stock	
10		
11	Account 211 - Miscellaneous Paid-In-Capital	
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40	TOTAL	614,648,268

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	04/11/2014	End of 2013/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		
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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	04/11/2014	End of 2013/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		
10	Note Payable to Parent Company (American Electric Power Company) - 5.250%	20,000,000	
11	SUBTOTAL ACCOUNT 223 - ADVANCES FROM ASSOCIATED COMPANIES	20,000,000	
12			
13	ACCOUNT 224 - OTHER LONG-TERM DEBT		
14	Senior Unsecured Notes - 5.625%, Series D	75,000,000	736,575
15			
16	Senior Unsecured Notes - 6.000%, Series E	325,000,000	2,277,883
17	KPSC Authority Docket No.2006-0034		1,667,250 D
18			
19	Amortization of Cash Flow Hedges on 6.000% SUN		
20			
21	Senior Unsecured Notes - 7.250%, State Commission Authority Case # 2008-00442	40,000,000	217,919
22			
23	Senior Unsecured Notes - 8.030%, State Commission Authority Case # 2008-00442	30,000,000	148,032
24			
25	Senior Unsecured Notes - 8.130%, State Commission Authority Case # 2008-00442	60,000,000	342,285
26			
27	Floating Rate Term Credit Agreement, Due 2015		
28	FERC Docket EC-13-28-000 Authority	200,000,000	299,549
29			
30			
31	SUBTOTAL ACCOUNT 224 - OTHER LONG-TERM DEBT	730,000,000	5,689,493
32			
33	TOTAL	750,000,000	5,689,493

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)	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
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						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
12/31/2013	05/13/2015	12/31/2013	05/13/2015	200,000,000		28
						29
						30
				730,000,000	33,998,706	31
						32
				750,000,000	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	04/11/2014	2013/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	04/11/2014	End of 2013/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)	13,872,009
2		
3		
4	Taxable Income Not Reported on Books	
5		
6		
7		
8		
9	Deductions Recorded on Books Not Deducted for Return	
10		
11		
12		
13		
14	Income Recorded on Books Not Included in Return	
15		
16		
17		
18		
19	Deductions on Return Not Charged Against Book Income	
20		
21		
22		
23		
24		
25		
26		
27	Federal Tax Net Income	21,729,420
28	Show Computation of Tax:	
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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	04/11/2014	2013/Q4

FOOTNOTE DATA

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

Name of Respondent			Year/Period of Report
Kentucky Power Company			2013/Q4

Schedule Page: 261 Line No.: 29 Column: b

	In (000's)
Net Income for the year per Page 117, Line 78	13,872
Federal Income Taxes	7,637
State Income Taxes	2,501
Pretax Book Income	24,010
Increase (Decrease) in Taxable Income resulting from:	
Allowance for Funds Used During Construction and Other Differences between Items Capitalizes for Books and Expensed for Tax	(392)
Capitalized Relocation Costs	0
Deferred Fuel Cost (Net)	(5,078)
Deferred Storm Damage	4,698
Demand Side Management (Net)	675
Emission Allowances (Net)	(4,263)
Excess Tax Vs. Book Depreciation	(30,472)
Mark-to-Market	2,127
Pension Expenses (Net)	3,011
RTO Expenses and Carrying Charges	188
Removal Costs - ACRS	(7,072)
Repair Allowance	0
Book Unit of Property Adjustment	(50)
Self Insurance - Book Reserve	99
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)	(1,123)
Medicare subsidy	0
Tax Accruals and Deferrals	(300)
Pollution Control Equipment	4,500
Accrd Book ARO Exp	(322)
Misc Book Accruals, Reserves and Deferrals	33,096
Provision for Possible Revenue Refunds	(2,421)
Sales & Use Tax Reserves	453
Accrued Tax Reserve - FIN 48	(5)
Accrued Interest - Long & Short Term	111
Mitigation Programs - Federal & State	(268)
Non-Deductible Fines & Penalties	4
Other (Net)	3,204
Federal Taxable Income before State Income Taxes	24,410
State Income Taxes	2,681

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	04/11/2014	2013/Q4

FOOTNOTE DATA

Federal Taxable Net Income - Estimated Current Year Taxable Income (Separate Return Basis)		21,729
Computation of Tax		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		7,605
Adjustment due to System Consolidation	(a)	(293)
Tax Provision Adjustment		0
Audit Settlement		(1,056)
R&D Credit		0
Estimated Tax Currently Payable	(b)	6,256
Adjustments of Prior Year's Accruals (Net)		(2,835)
Estimated Current Federal Income Taxes (Net)		3,421

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 the 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 2013 system Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2014. 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	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	-5,089,401		3,421,412	2,591,448	85,022
3	INCOME TAX - IRS Audit	14,832				-14,832
4	FICA - 2013	357,577		2,465,814	2,485,869	
5	Unemployment - 2013	17,606		47,465	34,832	
6						
7	Federal Excise Tax - 2013			2,489	2,489	
8						
9	STATE INC. TAX - FIN 48	-7,192		-5,418		
10						
11	STATE OF ILLINOIS:					
12	Income 2011					
13	2012	33,921		-94,182	-60,261	
14	2013			67,018	168,361	
15	STATE OF KENTUCKY:					
16	Income 2011					
17	2012	41,486		-79,399	-37,913	
18	2013			2,609,022	3,437,913	
19	License Fee 2013			340	340	
20						
21						
22						
23	Unemployment - KY 2013	274		45,408	37,583	
24						
25	PUBLIC SER COMM'S-2012		515,095	515,095		
26	PUBLIC SER COMM'S-2013			473,122	946,244	
27	USE TAX - 2012	251,468	42,719	24,843	233,592	
28	USE TAX - 2013			1,207,682	1,139,572	
29	SALES TAX - 2012		294,773		-294,773	
30	SALES TAX - 2013				274,001	
31	REAL & PERS PROP-2008			811	811	
32	REAL & PERS PROP-2010	96,737		63,659	160,396	
33	REAL & PERS PROP-2011	530,458		15,173	545,631	
34	REAL & PERS PROP-2012	10,424,707			5,742,893	
35	REAL & PERS PROP-2013			10,800,840		
36	PERS PROP LEASED-2011	10,268		-10,026	242	
37	PERS PROP LEASED-2012	4,373		-4,165	208	
38	PERS PROP LEASED-2013			17,300	23	
39	REAL PROP LEASES-2013			27,000	12,302	
40						
41	TOTAL	6,548,715	852,587	22,121,550	17,397,618	4,245,190

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	04/11/2014	End of 2013/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	STATE OF WEST VIRGINIA:					
2	Income 2009	-63,670				
3	2012	-49,500		-6,378	-55,878	
4	2013			7,407	49,500	
5	Franchise - 2011					
6	2012	-27,955		-9,120	-37,075	
7	2013			3,782	38,300	
8	USE - 2012	1,144		-402	742	
9	USE - 2013			5,056	4,480	
10	USE - Audit			452,900		
11	Real & Pers Prop Taxes			2,051	2,051	
12	Real & Pers Prop Taxes					1,430,000
13	Real & Pers Prop Taxes					2,745,000
14						
15	PERS PROP LEASED-2012			863	863	
16						
17	WV License Fee - 2013			45	45	
18						
19	WV State Unemployment -			1,504	1,260	
20	OK State License Fee 2012					
21	Michigan License Fee 2011					
22	Tennessee License Fee 2011					
23	Utah License Fee 2011					
24	Wyoming License Fee 2011					
25						
26	STATE OF OHIO:					
27	Income - 2000					
28						
29	OH CAT TAX - 2012	33,000		-31,461	1,539	
30	OH CAT TAX - 2013			54,373	39,373	
31	OH CAT TAX - Refunds			-44,951	-44,951	
32	STATE OF MICHIGAN:					
33	Income 2011					
34	2012	-31,218		-150	-31,368	
35	2013			3,170	6,934	
36	OTHER:					
37	REAL/PERS PROP-LA-2012	-200		200		
38	PA License Fee - 2009					
39	PA Gross Receipts - Audit			71,358		
40						
41	TOTAL	6,548,715	852,587	22,121,550	17,397,618	4,245,190

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 (I) 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
-4,174,415		2,940,817			480,595	2
						3
337,522		1,421,332			1,044,482	4
30,239		39,040			8,425	5
						6
		2,489				7
						8
-12,610		-5,418				9
						10
						11
						12
		-93,908			-274	13
-101,343		62,215			4,803	14
						15
						16
		-74,879			-4,520	17
-828,891		2,407,743			201,279	18
		340				19
						20
						21
						22
8,099		30,355			15,053	23
						24
		515,095				25
	473,122	473,122				26
		1,109			23,734	27
115,170	47,060	11,175			1,196,507	28
						29
	274,001					30
		811				31
		66,347			-2,688	32
		15,173				33
4,681,814		9,939,409			-9,939,409	34
10,800,840					10,800,840	35
		-10,026				36
		-4,165				37
17,277		17,300				38
14,698		27,000				39
						40
15,459,433	794,183	18,178,980			3,942,570	41

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 (I) 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
-63,670						2
		-6,310			-68	3
-42,093		5,598			1,809	4
						5
		-9,120				6
-34,518		3,782				7
					-402	8
576					5,056	9
452,900		342,470			110,430	10
					2,051	11
1,430,000						12
2,745,000						13
						14
		863				15
						16
		45				17
						18
244		1,000			504	19
						20
						21
						22
						23
						24
						25
						26
						27
						28
		-31,461				29
15,000		54,373				30
		-39,083			-5,868	31
						32
						33
		-145			-5	34
-3,764		2,934			236	35
						36
		200				37
						38
71,358		71,358				39
						40
15,459,433	794,183	18,178,980			3,942,570	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	04/11/2014	2013/Q4

FOOTNOTE DATA

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

$70,939 - Tax Credit Carryforward
$14,082 - IRS Audit Reclass
$1 - Other Reclass

85,022

Schedule Page: 262 Line No.: 3 Column: f

IRS Audit Reclass $14,832

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.

Schedule Page: 262.1 Line No.: 12 Column: f

Transfer to Kentucky Power their portion of the Mitchell Plant property tax liability as a result of corporate separation.

Schedule Page: 262.1 Line No.: 13 Column: f

Transfer to Kentucky Power their portion of the Mitchell Plant property tax liability as a result of corporate separation.

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	04/11/2014	End of 2013/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year		Allocations to Current Year's Income		Adjustments (g)
			Account No. (c)	Amount (d)	Account No. (e)	Amount (f)	
1	Electric Utility						
2	3%						
3	4%						
4	7%						
5	10%	355,759			411.4	230,012	
6							
7							
8	TOTAL	355,759				230,012	
9	Other (List separately and show 3%, 4%, 7%, 10% and TOTAL)						
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
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41							
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43							
44							
45							
46							
47							
48							

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
125,747	Various		5
			6
			7
125,747			8
			9
			10
			11
			12
			13
			14
			15
			16
			17
			18
			19
			20
			21
			22
			23
			24
			25
			26
			27
			28
			30
			31
			32
			33
			34
			35
			36
			37
			38
			39
			40
			41
			42
			43
			44
			45
			46
			47
			48

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	78,940	454	619,641	631,529	90,828
2						
3	Customer Advance Receipts	2,634,498	142, 143	22,376,329	21,728,515	1,986,684
4						
5	Deferred Gain:	162,614	124	5,682		156,932
6	Fiber Optic Agrmts-In Kind Svc					
7	Amortize through June 2026					
8						
9	Deferred Revenue	116,729	451	13,556		103,173
10	Fiber Optic Lines-Sold-Defd Rev					
11	Amortize through January 2025					
12						
13	IPP - System Upgrade Credits	260,279			8,563	268,842
14						
15	Miscellaneous	6,461	Various	7,027	21,050	20,484
16						
17	Federal Mitigation Deferral (NSR)	754,942			355,702	1,110,644
18						
19	Contract Settlement Reserve	987,973	Various	776,309	9,954	221,618
20						
21	Fiber Optic Annual Maintenance	118,893	143	118,893		
22						
23						
24						
25						
26						
27						
28						
29						
30						
31						
32						
33						
34						
35						
36						
37						
38						
39						
40						
41						
42						
43						
44						
45						
46						
47	TOTAL	5,121,329		23,917,437	22,755,313	3,959,205

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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 269 Line No.: 17 Column: e

Amount includes Deferred Credits related to Mitchell Plant transfer to KPCo on 12/31/2013.

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	04/11/2014	End of 2013/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	26,644,638		1,584,930
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	26,644,638		1,584,930
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)	26,644,638		1,584,930
18	Classification of TOTAL			
19	Federal Income Tax	26,644,638		1,584,930
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	04/11/2014	End of 2013/Q4

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
							3
				Various	61,534,010	86,593,718	4
							5
							6
							7
					61,534,010	86,593,718	8
							9
							10
							11
							12
							13
							14
							15
							16
					61,534,010	86,593,718	17
							18
					61,534,011	86,593,719	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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 272 Line No.: 4 Column: j

NOTE> ADFIT credited to account 281 as a result of the transfer of 50% of Mitchell Plant from Ohio Power Company to Kentucky Power Company as a part of Corporate Separation.

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	04/11/2014	End of 2013/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)	Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	198,723,117	25,784,035	8,870,312
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	198,723,117	25,784,035	8,870,312
6	SFAS 109	53,778,616		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	252,501,733	25,784,035	8,870,312
10	Classification of TOTAL			
11	Federal Income Tax	252,501,733	25,784,035	8,870,312
12	State Income Tax			
13	Local Income Tax			

NOTES

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

3. Use footnotes as required.

CHANGES DURING YEAR		ADJUSTMENTS					
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits		Balance at End of Year	Line No.
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
				Various	93,123,611	308,760,451	2
							3
							4
					93,123,611	308,760,451	5
				Various	1,680,602	55,459,218	6
							7
							8
					94,804,213	364,219,669	9
							10
					94,804,213	364,219,669	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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 274 Line No.: 2 Column: j

ADFIT credited to account 282 as a result of the transfer of 50% of Mitchell Plant from Ohio Power Company to Kentucky Power Company as a part of Corporate Separation.

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	04/11/2014	End of 2013/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Fuel Costs	4,335,393	3,365,650	4,150,133
4	Mark to Market	3,499,149	560,189	2,002,580
5	Capitalized Software - Book	1,811,061	208,794	64,765
6	SFAS 158	1,539,373	5,382,925	9,756,145
7	Reg Asset - SFAS 112	1,830,400	904,502	1,149,483
8	Other	5,518,226	3,513,542	1,965,289
9	TOTAL Electric (Total of lines 3 thru 8)	18,533,602	13,935,602	19,088,395
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	87,473,193		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	106,006,795	13,935,602	19,088,395
20	Classification of TOTAL			
21	Federal Income Tax	63,662,104	14,845,406	19,088,395
22	State Income Tax	42,344,691		
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	04/11/2014	End of 2013/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					
		Debits		Credits			
Amounts Debited to Account 410.2 (e)	Amounts Credited to Account 411.2 (f)	Account Credited (g)	Amount (h)	Account Debited (i)	Amount (j)	Balance at End of Year (k)	Line No.
							1
							2
						3,550,910	3
						2,056,758	4
						1,955,090	5
		Various	7,959,442	Various	7,375,173	-3,418,116	6
						1,585,419	7
		Various	227,303	Various	25,781,548	32,620,724	8
			8,186,745		33,156,721	38,350,785	9
							10
							11
							12
							13
							14
							15
							16
							17
7,811		Various	9,027,360	Various	45,508,122	123,961,766	18
7,811			17,214,105		78,664,843	162,312,551	19
							20
7,811		Various	14,290,123	Various	36,732,008	81,868,811	21
		Various	2,923,982	Various	41,023,031	80,443,740	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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 276 Line No.: 6 Column: j

ADFIT debited and credited to account 283 as a result of the transfer of 50% of Mitchell Plant from Ohio Power Generation to Kentucky Power Generation as a part of Corporate Separation.

Schedule Page: 276 Line No.: 8 Column: j

ADFIT and ADSIT debited and credited to account 283 as a result of the transfer of 50% of Mitchell Plant from Ohio Power Generation to Kentucky Power Generation as a part of Corporate Separation.

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

	Beginning Balance	Ending Balance
Non-Utility	75,853	129,391
SFAS 109	87,374,194	123,799,574
SFAS 133	23,146	32,801
	87,473,193	123,961,766

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	04/11/2014	End of 2013/Q4

OTHER REGULATORY LIABILITIES (Account 254)

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

Line No.	Description and Purpose of Other Regulatory Liabilities	Balance at Begining of Current Quarter/Year	DEBITS		Credits	Balance at End of Current Quarter/Year
			Account Credited	Amount		
	(a)	(b)	(c)	(d)	(e)	(f)
1	Home Energy Assistance Program	233,489	Various	386,978	463,410	309,921
2						
3	SFAS 109 Deferred FIT	1,166,821	Various	175,302	6,011	997,530
4						
5	Unrealized Gain on Forward Commitments	4,287,555	Various	17,459,498	16,430,637	3,258,694
6						
7	Green Pricing Option	614				614
8						
9	Over Recovered Fuel Cost	7,928,323	Various	7,928,323	2,850,638	2,850,638
10						
11	Kentucky Enhanced Reliability	215,164	Various	256,669	41,505	
12						
13						
14						
15						
16						
17						
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39						
40						
41	TOTAL	13,831,966		26,206,770	19,792,201	7,417,397

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	215,884,709	205,798,905
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	128,311,276	125,717,218
5	Large (or Ind.) (See Instr. 4)	166,444,950	167,974,954
6	(444) Public Street and Highway Lighting	1,560,346	1,545,674
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	512,201,281	501,036,751
11	(447) Sales for Resale	122,418,742	100,941,442
12	TOTAL Sales of Electricity	634,620,023	601,978,193
13	(Less) (449.1) Provision for Rate Refunds	-478,327	1,635,430
14	TOTAL Revenues Net of Prov. for Refunds	635,098,350	600,342,763
15	Other Operating Revenues		
16	(450) Forfeited Discounts	3,340,356	3,268,233
17	(451) Miscellaneous Service Revenues	380,114	353,912
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	6,403,606	7,006,537
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	3,844,369	3,289,883
22	(456.1) Revenues from Transmission of Electricity of Others	17,524,583	17,193,946
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	31,493,028	31,112,511
27	TOTAL Electric Operating Revenues	666,591,378	631,455,274

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
2,311,805	2,240,727	140,164	140,929	2
				3
1,345,467	1,349,653	30,265	30,059	4
2,869,662	3,059,752	1,324	1,368	5
10,587	10,524	385	401	6
				7
				8
				9
6,537,521	6,660,656	172,138	172,757	10
3,396,006	2,936,231	82	102	11
9,933,527	9,596,887	172,220	172,859	12
				13
9,933,527	9,596,887	172,220	172,859	14

Line 12, column (b) includes $ -1,197,797 of unbilled revenues.
Line 12, column (d) includes -37,129 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	04/11/2014	2013/Q4

FOOTNOTE DATA

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

Detail of Unmetered Sales:

	Revenue	MWH	Average Customers
Residential	5,007,159	26,741	40,046
Commercial	2,268,847	15,423	7,149
Industrial	123,513	923	252
Public Street Lighting	23,112	110	36
Total	7,422,631	43,197	47,483

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

Customer Service Revenues (1)	$	366,058
All other under $25,000 each		14,056
	$	380,114

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

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

	Description	YTD
4560007	Oth Elec Rev - Demand Side Management Program	3,323,488
4560015	Other Electric Revenues - ABD	479,654
	All Other (under $250,000)	41,227
		3,844,369

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	04/11/2014	End of 2013/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					
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41					
42					
43					
44					
45					
46	TOTAL				

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	2,298,845	211,167,142	140,058	16,414	0.0919
3	Res Service Load Management	2,522	201,883	97	26,000	0.0800
4	Residential Service TOD	45	3,900	3	15,000	0.0867
5	Small General Service	46	5,086	5	9,200	0.1106
6	Medium General Service	4	760	1	4,000	0.1900
7	All Outdoor Lighting	26,741	5,007,159			0.1872
8	Subtotal Billed	2,328,203	216,385,930	140,164	16,611	0.0929
9	Unbilled Revenue	-16,398	-501,221			0.0306
10	Total Residential	2,311,805	215,884,709	140,164	16,494	0.0934
11						
12	442 Commercial Sales					
13	Small General Service	135,025	16,392,138	22,543	5,990	0.1214
14	Medium General Service	477,923	49,555,723	6,903	69,234	0.1037
15	Medium General Service TOD	3,770	334,986	75	50,267	0.0889
16	Large General Service	543,633	48,854,428	708	767,843	0.0899
17	Quantity Power	179,158	11,279,489	25	7,166,320	0.0630
18	All Outdoor Lighting	15,423	2,268,847			0.1471
19	Mark West HC	3,909	329,133	11	355,364	0.0842
20	Estimated Revenue	-3,686	-291,248			0.0790
21	Subtotal Billed	1,355,155	128,723,496	30,265	44,776	0.0950
22	Unbilled Revenue	-9,688	-412,220			0.0425
23	Total Commercial	1,345,467	128,311,276	30,265	44,456	0.0954
24						
25	442 Industrial Sales					
26	Small General Service	5,216	596,181	745	7,001	0.1143
27	Medium General Service	27,562	2,805,930	359	76,774	0.1018
28	Large General Service	148,421	12,811,578	153	970,072	0.0863
29	Quantity Power	494,287	33,506,802	51	9,691,902	0.0678
30	Commercial & Industrial Power	2,198,842	115,360,581	16	137,427,625	0.0525
31	All Outdoor Lighting	923	123,513			0.1338
32	Estimated Revenue	5,431	1,522,904			0.2804
33	Subtotal Billed	2,880,682	166,727,489	1,324	2,175,742	0.0579
34	Unbilled Revenue	-11,020	-282,539			0.0256
35	Total Industrial	2,869,662	166,444,950	1,324	2,167,418	0.0580
36						
37						
38						
39						
40						
41	TOTAL Billed	6,574,650	513,399,078	172,138	38,194	0.0781
42	Total Unbilled Rev.(See Instr. 6)	-37,129	-1,197,797	0	0	0.0323
43	TOTAL	6,537,521	512,201,281	172,138	37,978	0.0783

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	04/11/2014	End of 2013/Q4

SALES OF ELECTRICITY BY RATE SCHEDULES

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

Line No.	Number and Title of Rate schedule (a)	MWh Sold (b)	Revenue (c)	Average Number of Customers (d)	KWh of Sales Per Customer (e)	Revenue Per KWh Sold (f)
1						
2	444 Public Street Lighting					
3	Small General Service	735	121,235	318	2,311	0.1649
4	Medium General Service	1,225	120,782	11	111,364	0.0986
5	Street Lighting	8,540	1,297,034	56	152,500	0.1519
6	All Outdoor Lighting	110	23,112			0.2101
7	Subtotal Billed	10,610	1,562,163	385	27,558	0.1472
8	Unbilled Revenue	-23	-1,817			0.0790
9	Total Public Street Lighting	10,587	1,560,346	385	27,499	0.1474
10						
11	Instruction 5. (See Footnote)					
12						
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40						
41	TOTAL Billed	6,574,650	513,399,078	172,138	38,194	0.0781
42	Total Unbilled Rev.(See Instr. 6)	-37,129	-1,197,797	0	0	0.0323
43	TOTAL	6,537,521	512,201,281	172,138	37,978	0.0783

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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 304.1 Line No.: 11 Column: a

FUEL CLAUSE

440 Residential	
Residential Service	811,421
Res Service Load Management	259
Residential Service TOD	12
All Outdoor Lighting	6,204
Small General Service	20
Medium General Service	(11)
Unbilled	986,870
Total Residential	1,804,775
442 Commercial	
Mark West HC	2,226
Small General Service	65,016
Medium General Service	303,119
Medium General Service TOD	2,312
Large General Service	335,966
Quantity Power	133,487
All Outdoor Lighting	3,785
Estimated	275
Unbilled	483,300
Total Commercial	1,329,486
442 Industrial	
Small General Service	1,931
Medium General Service	8,034
Large General Service	79,958
Quantity Power	301,143
Commercial & Industrial TOD	1,224,342
All Outdoor Lighting	230
Estimated	169,455
Unbilled	402,261
Total Industrial	2,187,354
444 Public Street Lighting	
Small General Service	269
Medium General Service	421
Street Lighting	2,129
All Outdoor Lighting	26
Unbilled	971
Total Public Street Light	3,816
TOTAL FUEL CLAUSE	5,325,431

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	04/11/2014	End of 2013/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)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	CITY OF OLIVE HILL	RQ	KPCO 52			
2	CITY OF VANCEBURG	RQ	KPCO 51			
3	PJM TRANSMISSION FOR RQ	RQ	Various			
4	ADJUSTMENT	OS	See footnote			
5	AEP SERVICE CORPORATION	OS	11			
6	AEP SERVICE CORPORATION	OS	20			
7	ALLEGHENY ELECTRIC COOPERATIVE	OS	Note 1			
8	AMEREN CILCO	OS	Note 1			
9	AMEREN ENERGY MARKETING	OS	Note 1			
10	AMERICAN MUNICIPAL POWER - OHIO	OS	Note 1			
11	AMERICAN POWERNET MANAGEMENT	OS	Note 1			
12	ASSOCIATED ELECT COOPERATIVE	OS	Note 1			
13	B.P. ENERGY COMPANY	OS	Note 1			
14	BARCLAYS BANK PLC	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	04/11/2014	End of 2013/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)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	BEECH RIDGE ENERGY LLC	OS	Note 1			
2	BP AMOCO	OS	Note 1			
3	BUCKEYE RURAL ELECTRIC	OS	Note 1			
4	CALPINE POWER SERVICE COMPANY	OS	Note 1			
5	CAROLINA POWER & LIGHT	OS	Note 1			
6	CITIGROUP ENERGY INC.	OS	Note 1			
7	CITY OF BANGOR, WISCONSIN	OS	Note 1			
8	CITY OF BARRON, WISCONSIN	OS	Note 1			
9	CITY OF BATAVIA	OS	Note 1			
10	CITY OF BLOOMER, WISCONSIN	OS	Note 1			
11	CITY OF COLUMBUS	OS	Note 1			
12	CITY OF CORNELL, WISCONSIN	OS	Note 1			
13	CITY OF CROSWELL, MI	OS	Note 1			
14	CITY OF KIRKWOOD, MISSOURI	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	04/11/2014	End of 2013/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)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	CITY OF MEDFORD	OS	Note 1			
2	CITY OF RICE LAKE UTILITIES	OS	Note 1			
3	CITY OF SHELBY	OS	Note 1			
4	CITY OF SPOONER, WISCONSIN	OS	Note 1			
5	CITY OF WAKEFIELD, WISCONSIN	OS	Note 1			
6	CITY OF WESTERVILLE	OS	Note 1			
7	CLEVELAND PUBLIC POWER	OS	Note 1			
8	CLEVELAND TOLEDO OH PA ELECTRIC	OS	Note 1			
9	COMMONWEALTH EDISON COMPANY	OS	Note 1			
10	CONOCO INC.	OS	Note 1			
11	CONSTELLATION ENGY COMMODITIES	OS	Note 1			
12	COOK INLET ENERGY SUPPLY LP	OS	Note 1			
13	DAIRYLAND POWER COOPERATIVE	OS	Note 1			
14	DB ENERGY TRADING LLC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

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)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	DELMARVA POWER & LIGHT	OS	Note 1			
2	DP&L POWER SERVICES	OS	Note 1			
3	DTE ENERGY TRADING INC.	OS	Note 1			
4	DUKE ENERGY CAROLINAS, LLC	OS	Note 1			
5	DUKE ENERGY INDIANA, INC.	OS	Note 1			
6	DUKE ENERGY OHIO, INC	OS	Note 1			
7	EAST KY POWER CO-OP POWER MKTG	OS	See footnote			
8	EASTON UTILITIES	OS	Note 1			
9	EDF TRADING NORTH AMERICA LLC	OS	Note 1			
10	EDISON MISSION MKTG & TRADING	OS	Note 1			
11	ENDURE ENERGY, LLC	OS	Note 1			
12	ENERGY AMERICA, LLC	OS	Note 1			
13	ENG MKTG, DIV OF AMERADA HESS	OS	Note 1			
14	ENTERGY POWER SERV	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	04/11/2014	End of 2013/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:
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	EXELON GENERATION - POWER TEAM	OS	Note 1			
2	FIRSTENERGY TRADING SERVICES	OS	Note 1			
3	GBC METALS, LLC	OS	Note 1			
4	HARRISON RURAL ELECTRIFICATION	OS	Note 1			
5	INDIANAPOLIS POWER & LIGHT CO	OS	Note 1			
6	INTEGRYS ENERGY SERVICES, INC	OS	Note 1			
7	INTERSTATE GAS SUPPLY, INC.	OS	Note 1			
8	INTERSTATE POWER & LIGHT CO	OS	Note 1			
9	J ARON & COMPANY	OS	Note 1			
10	JP MORGAN VENTURES ENERGY CORP	OS	Note 1			
11	KANSAS CITY POWER & LIGHT CO	OS	Note 1			
12	LETTERKENNY INDUSTRIL DEV AUTH	OS	Note 1			
13	LG&E UTILITIES POWER SALES	OS	Note 1			
14	MICHIGAN PUBLIC POWER AGENCY	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	04/11/2014	End of 2013/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.
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Line No.	Name of Company or Public Authority (Footnote Affiliations)	Statistical Classification	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	MIDAMERICAN ENERGY	OS	Note 1			
2	MIDWEST ISO	OS	Note 1			
3	MIZUHO SECURITIES USA INC	OS	Note 1			
4	MORGAN STANLEY CAPT.	OS	Note 1			
5	NC ELECTRIC MEMBERSHIP CORP.	OS	Note 1			
6	NEXTERA ENERGY POWER MKTG LLC	OS	Note 1			
7	NOBLE AMERICAS GAS AND POWER	OS	Note 1			
8	NRG POWER MARKETING INC.	OS	Note 1			
9	NSP ENERGY MARKETING	OS	Note 1			
10	OLD DOMINION ELEC.	OS	Note 1			
11	OPC VARIABLE	OS	Note 1			
12	OTTER TAIL POWER COMPANY	OS	Note 1			
13	OVEC POWER SCHEDULING	OS	Note 1			
14	PARIBAS	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	04/11/2014	End of 2013/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.
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	(a)	(b)	(c)	(d)	(e)	(f)
1	PAULDING WIND FARM II, LLC	OS	Note 1			
2	PJM INTERCONNECTION	OS	Note 1			
3	POTOMAC ELECTRIC POWER COMPANY	OS	Note 1			
4	PP&L ENERGY PLUS CO.	OS	Note 1			
5	PPL ELECTRIC UTILITIES CORP	OS	Note 1			
6	PRAIRIE POWER, INC.	OS	Note 1			
7	PRAIRIELAND ENERGY INCORPORATE	OS	Note 1			
8	SEMPRA ENERGY SOLUTIONS, LLC	OS	Note 1			
9	SOUTHERN COMPANY	OS	Note 1			
10	THE BOROUGH OF PITCAIRN, PA	OS	Note 1			
11	THE ENERGY AUTHORITY	OS	Note 1			
12	TOWN OF BERLIN, MARYLAND	OS	Note 1			
13	TOWN OF HAGERSTOWN, INDIANA	OS	Note 1			
14	TVA BULK POWER TRADING	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

SALES FOR RESALE (Account 447)

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	(a)	(b)	(c)	(d)	(e)	(f)
1	UBS AG, LONDON BRANCH	OS	Note 1			
2	UBS SECURITIES LLC	OS	Note 1			
3	UGI UTILITIES	OS	Note 1			
4	UNION ELECTRIC COMPANY	OS	Note 1			
5	UNION POWER PARTNERS	OS	Note 1			
6	VILLAGE OF BETHEL OHIO	OS	Note 1			
7	VILLAGE OF CADOTT, WISCONSIN	OS	Note 1			
8	VILLAGE OF GLOUSTER	OS	Note 1			
9	VILLAGE OF HAMERSVILLE, OHIO	OS	Note 1			
10	VILLAGE OF RIPLEY OHIO	OS	Note 1			
11	VILLAGE OF SEBEWAING, MI	OS	Note 1			
12	VILLAGE OF TREMPEALEAU, WISCONSIN	OS	Note 1			
13	WABASH VALLEY POWER ASSN INC.	OS	Note 1			
14	WASHINGTON GAS ENERGY SERVICES	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	04/11/2014	End of 2013/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)	Statistical Classifi-cation	FERC Rate Schedule or Tariff Number	Average Monthly Billing Demand (MW)	Actual Demand (MW)	
					Average Monthly NCP Demand	Average Monthly CP Demand
	(a)	(b)	(c)	(d)	(e)	(f)
1	WESTAR ENERGY INC.	OS	Note 1			
2	WILDCAT WIND FARM	OS	Note 1			
3	WISCONSIN POWER & LIGHT	OS	Note 1			
4	WOLVERINE POWER SUPPLY COOP	OS	Note 1			
5						
6						
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
24,869	514,673	973,098		1,487,771	1
69,259	1,319,478	2,483,368		3,802,846	2
			-640,793	-640,793	3
		21,003		21,003	4
1,418,388		43,489,882		43,489,882	5
3,935		120,330		120,330	6
1,110		55,871		55,871	7
5,507		184,343		184,343	8
-3,315		-61,567		-61,567	9
10,737	36,469	560,214		596,683	10
4,530		187,860		187,860	11
-555		-18,223		-18,223	12
-996		-91,162		-91,162	13
1,761		-10,827		-10,827	14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

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.
		-11,465		-11,465	1
		-13,545		-13,545	2
19,479		5,944,109		5,944,109	3
-100		-3,386		-3,386	4
					5
94		3,953		3,953	6
1,777		110,523		110,523	7
5,287		323,241		323,241	8
1,608		68,740		68,740	9
3,432		209,966		209,966	10
53,759		3,599,405		3,599,405	11
912		55,644		55,644	12
2,611		129,674		129,674	13
1,608		84,016		84,016	14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

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)
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.
8,135		483,937		483,937	1
10,254		635,686		635,686	2
1,735		126,909		126,909	3
2,138		129,986		129,986	4
901		54,008		54,008	5
30,924		2,377,418		2,377,418	6
					7
	16,990	-292		16,698	8
15,604		499,800		499,800	9
		32,575		32,575	10
-52		-7,194		-7,194	11
		-59,158		-59,158	12
		-211		-211	13
		-78,648		-78,648	14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

SALES FOR RESALE (Account 447) (Continued)

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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.
		-1,265		-1,265	1
		106,572		106,572	2
		-14,244		-14,244	3
		-811		-811	4
					5
9,901		482,816		482,816	6
27,526		1,056,340		1,056,340	7
1,648		71,610		71,610	8
12,460		513,010		513,010	9
	29,922			29,922	10
		-446		-446	11
		64,219		64,219	12
		76,009		76,009	13
		-1,666		-1,666	14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

SALES FOR RESALE (Account 447) (Continued)

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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.
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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.
-3,342		-1,598,674		-1,598,674	1
86,696		4,602,932		4,602,932	2
					3
6,379		494,902		494,902	4
	1,239			1,239	5
		39,266		39,266	6
1,469		53,637		53,637	7
		2,958		2,958	8
54,988		1,705,155		1,705,155	9
4,520		-331,318		-331,318	10
-214		-7,193		-7,193	11
1,917		120,911		120,911	12
					13
4,072		272,038		272,038	14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

SALES FOR RESALE (Account 447) (Continued)

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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.
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10. Footnote entries as required and provide explanations following all required data.

MegaWatt Hours Sold (g)	REVENUE: Demand Charges ($) (h)	REVENUE: Energy Charges ($) (i)	REVENUE: Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		10,661		10,661	1
-122,075		-4,440,469		-4,440,469	2
		622,366		622,366	3
246		-357,020		-357,020	4
54,866		2,360,807		2,360,807	5
296		170,117		170,117	6
		31,757		31,757	7
2,586	3,628	58,074		61,702	8
					9
49		1,771		1,771	10
					11
		-3		-3	12
		15		15	13
		4		4	14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

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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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.
		-14,427		-14,427	1
1,481,839	367,494	49,332,528		49,700,022	2
6,333		448,580		448,580	3
		172,709		172,709	4
124		8,230		8,230	5
3,963		213,294		213,294	6
5,569		189,279		189,279	7
		-7,332		-7,332	8
1,240		47,119		47,119	9
809		38,081		38,081	10
56		2,256		2,256	11
1,201		76,540		76,540	12
1,463		91,263		91,263	13
489		21,670		21,670	14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

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.
		-32,459		-32,459	1
		-1,124,866		-1,124,866	2
1,828		94,276		94,276	3
		17,493		17,493	4
-1,181		-36,400		-36,400	5
1,836		95,152		95,152	6
896		55,746		55,746	7
83		14,861		14,861	8
337		20,116		20,116	9
1,218		63,268		63,268	10
3,037		143,702		143,702	11
1,061		66,708		66,708	12
					13
14,454		617,195		617,195	14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

SALES FOR RESALE (Account 447) (Continued)

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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.
-1,879		-65,142		-65,142	1
		-11,787		-11,787	2
4,532		159,676		159,676	3
27,374	101	1,317,493		1,317,594	4
					5
					6
					7
					8
					9
					10
					11
					12
					13
					14
94,128	1,834,151	3,456,466	-640,793	4,649,824	
3,301,878	455,843	117,313,075	0	117,768,918	
3,396,006	**2,289,994**	**120,769,541**	**-640,793**	**122,418,742**	

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) 04/11/2014	2013/Q4

FOOTNOTE DATA

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

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

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

Amount represents transmission services and related charges.

Schedule Page: 310 Line No.: 4 Column: 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.: 5 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and were 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 were governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and were processed by American Electric Power Service. See Notes to Financial Statements for discussion of termination of interconnection agreement as of 12/31/2013.

Schedule Page: 310 Line No.: 6 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.: 7 Column: c

FERC Electric Tariff, First Revised Volume No. 5

Schedule Page: 310.3 Line No.: 7 Column: c

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

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	1,797,648	2,064,333
5	(501) Fuel	93,485,022	93,157,360
6	(502) Steam Expenses	2,941,410	2,759,155
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	399,129	295,080
10	(506) Miscellaneous Steam Power Expenses	4,304,473	5,519,141
11	(507) Rents	900	
12	(509) Allowances	5,803,450	8,873,595
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	108,732,032	112,668,664
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	1,821,917	2,059,495
16	(511) Maintenance of Structures	872,830	573,927
17	(512) Maintenance of Boiler Plant	6,565,943	5,552,809
18	(513) Maintenance of Electric Plant	2,995,792	1,396,877
19	(514) Maintenance of Miscellaneous Steam Plant	578,915	617,125
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	12,835,397	10,200,233
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	121,567,429	122,868,897
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering	1,074	
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)	1,074	
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)	1,074	
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)		

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	296,482,810	247,203,291
77	(556) System Control and Load Dispatching	138,025	171,352
78	(557) Other Expenses	1,337,696	1,458,376
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	297,958,531	248,833,019
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	419,527,034	371,701,916
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	888,954	659,388
84			
85	(561.1) Load Dispatch-Reliability	9,421	5,642
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	821,922	764,533
87	(561.3) Load Dispatch-Transmission Service and Scheduling		-77
88	(561.4) Scheduling, System Control and Dispatch Services	955,673	1,160,718
89	(561.5) Reliability, Planning and Standards Development	145,934	136,890
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	225,073	245,515
93	(562) Station Expenses	313,852	188,431
94	(563) Overhead Lines Expenses	119,543	153,317
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	6,702,896	4,361,575
97	(566) Miscellaneous Transmission Expenses	1,115,512	1,208,167
98	(567) Rents	11,069	2,204
99	TOTAL Operation (Enter Total of lines 83 thru 98)	11,309,849	8,886,303
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	105,531	136,306
102	(569) Maintenance of Structures	10,780	27,527
103	(569.1) Maintenance of Computer Hardware	20,287	44,422
104	(569.2) Maintenance of Computer Software	285,718	204,089
105	(569.3) Maintenance of Communication Equipment	26,018	95,634
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	784,014	564,396
108	(571) Maintenance of Overhead Lines	1,773,834	2,075,115
109	(572) Maintenance of Underground Lines		
110	(573) Maintenance of Miscellaneous Transmission Plant	67,844	169,121
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,074,026	3,316,610
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	14,383,875	12,202,913

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	04/11/2014	End of 2013/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	985,648	1,194,322
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	985,648	1,194,322
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)	985,648	1,194,322
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	707,004	665,170
135	(581) Load Dispatching	3,131	2,293
136	(582) Station Expenses	163,715	179,855
137	(583) Overhead Line Expenses	577,534	187,323
138	(584) Underground Line Expenses	131,141	129,749
139	(585) Street Lighting and Signal System Expenses	118,881	100,429
140	(586) Meter Expenses	686,805	519,469
141	(587) Customer Installations Expenses	161,182	129,726
142	(588) Miscellaneous Expenses	4,021,874	5,407,980
143	(589) Rents	1,595,988	1,682,012
144	TOTAL Operation (Enter Total of lines 134 thru 143)	8,167,255	9,004,006
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	1,589	739
147	(591) Maintenance of Structures	32,058	24,153
148	(592) Maintenance of Station Equipment	768,334	517,533
149	(593) Maintenance of Overhead Lines	29,761,661	30,483,135
150	(594) Maintenance of Underground Lines	231,685	92,158
151	(595) Maintenance of Line Transformers	56,587	68,385
152	(596) Maintenance of Street Lighting and Signal Systems	59,381	43,716
153	(597) Maintenance of Meters	60,536	53,792
154	(598) Maintenance of Miscellaneous Distribution Plant	121,720	85,508
155	TOTAL Maintenance (Total of lines 146 thru 154)	31,093,551	31,369,119
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	39,260,806	40,373,125
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	285,400	272,442
160	(902) Meter Reading Expenses	483,691	453,028
161	(903) Customer Records and Collection Expenses	4,998,511	5,331,906
162	(904) Uncollectible Accounts	-54,515	152,616
163	(905) Miscellaneous Customer Accounts Expenses	20,469	16,264
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	5,733,556	6,226,256

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	147,648	211,612
168	(908) Customer Assistance Expenses	3,367,405	2,591,856
169	(909) Informational and Instructional Expenses	140,471	155,343
170	(910) Miscellaneous Customer Service and Informational Expenses	35,493	37,709
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	3,691,017	2,996,520
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		-5
175	(912) Demonstrating and Selling Expenses	30,713	2
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)	30,713	-3
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	9,407,773	6,723,161
182	(921) Office Supplies and Expenses	1,105,675	584,743
183	(Less) (922) Administrative Expenses Transferred-Credit	1,186,844	1,333,464
184	(923) Outside Services Employed	1,664,765	4,660,005
185	(924) Property Insurance	549,852	605,545
186	(925) Injuries and Damages	1,641,114	1,010,501
187	(926) Employee Pensions and Benefits	3,897,159	5,291,855
188	(927) Franchise Requirements	142,255	145,896
189	(928) Regulatory Commission Expenses	266,578	155,946
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	62,281	68,468
192	(930.2) Miscellaneous General Expenses	431,209	290,504
193	(931) Rents	208,534	124,108
194	TOTAL Operation (Enter Total of lines 181 thru 193)	18,190,351	18,327,268
195	Maintenance		
196	(935) Maintenance of General Plant	1,600,140	1,578,835
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	19,790,491	19,906,103
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	503,403,140	454,601,152

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) 04/11/2014	2013/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.: 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	04/11/2014	End of 2013/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	AEP Service Corporation	OS	20			
3	AEP Service Corporation	OS	11			
4	Ameren Energy Marketing	OS				
5	Associated Electric Cooperative	OS				
6	Beech Ridge Energy LLC	OS				
7	BP Energy Company	OS				
8	Buckeye Rural Electric Administration	OS				
9	CMS Marketing Svcs and Trading	OS				
10	DB Energy Trading LLC	OS				
11	Dynegy Power Marketing Inc.	OS				
12	EDF Trading North America LLC	OS				
13	Exelon Generation - Power Team	OS				
14	J ARON & Company	OS				
	Total					

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	JP Morgan Ventures Energy Corp	OS				
2	LG&E Utilities Power Sales	OS				
3	Midwest ISO	OS				
4	Mizuho Securities USA Inc	OS				
5	National Power Cooperative Inc	OS				
6	Paulding Wind Farm II, LLC	OS				
7	PJM Interconnection	OS				
8	TVA Bulk Power Trading	OS				
9	UBS Securities LLC	OS				
10	Wildcat Wind farm	OS				
11	Wisconsin Electric Power Co	OS				
12	Wisconsin Power & Light	OS				
13	Adjustment	OS				
14						
	Total					

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)	MegaWatt Hours Delivered (i)	COST/SETTLEMENT OF POWER Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	Line No.
2,371,266			46,637,770	61,155,752		107,793,522	1
18				974		974	2
4,814,405			27,967,887	139,733,812		167,701,699	3
			1,576			1,576	4
33				1,170		1,170	5
				-6,634		-6,634	6
				-41,898		-41,898	7
				138,549		138,549	8
			25,113			25,113	9
				17,664		17,664	10
			2,858			2,858	11
			41,060			41,060	12
				24,790		24,790	13
				136		136	14
7,600,111			74,929,369	221,553,441		296,482,810	

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)	
			47,497			47,497	1
95				4,138		4,138	2
1,686				68,114		68,114	3
				4,322		4,322	4
2,817			21,332	351,973		373,305	5
				-71,717		-71,717	6
375,459			183,320	19,281,054		19,464,374	7
34,332				807,465		807,465	8
				65,416		65,416	9
				-2,642		-2,642	10
			39			39	11
			917			917	12
				21,003		21,003	13
							14
7,600,111			74,929,369	221,553,441		296,482,810	

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) 04/11/2014	2013/Q4

FOOTNOTE DATA

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

Affiliated Company

Schedule Page: 326 Line No.: 2 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.: 3 Column: a

Appalachian Power Company, Indiana Michigan Power Company, Kentucky Power Company and Ohio Power Company are associated companies and were 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 were governed by the terms of the interconnection agreement dated July 6, 1951, as amended, and are processed by American Electric Power Service Corporation. See Notes to Financial Statements for discussion of termination of interconnection agreement as of 12/31/2013.

Schedule Page: 326.1 Line No.: 13 Column: a

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

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	04/11/2014	End of 2013/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	PJM Network Integ Trans Rev Whlsle	Various	Various	FNO
2	PJM Network Integ Trans Serv	Various	Various	FNO
3	PJM Trans Enhancement Rev	Various	Various	FNO
4	PJM Trans Enhancement Rev - Affil	Various	Various	FNS
5	PJM Trans Enhancement Rev Whlsle	Various	Various	FNO
6	PJM Network Integ Rev - Affil	Various	Various	FNS
7	PJM Point to Point Trans Serv	Various	Various	LFP
8	PJM Trans Owner Admin Revenue	Various	Various	OLF
9	PJM Trans Owner Serv Rev Whlsle	Various	Various	OLF
10	PJM Expansion Cost Recovery	Various	Various	OS
11	PJM Power Factor Credits Rev Whlsle	Various	Various	OS
12	RTO Formation Costs Recovery	Various	Various	OS
13	PJM Trans Owner Serv -Affil	Various	Various	OLF
14	East Kentucky Power Cooperative	Various	Various	OLF
15				
16				
17				
18				
19				
20				
21				
22				
23				
24				
25				
26				
27				
28				
29				
30				
31				
32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	Various	Various				1
PJM OATT	Various	Various				2
PJM OATT	Various	Various				3
PJM OATT	Various	Various				4
PJM OATT	Various	Various				5
PJM OATT	Various	Various				6
PJM OATT	Various	Various				7
PJM OATT	Various	Various				8
PJM OATT	Various	Various				9
PJM OATT	Various	Various				10
PJM OATT	Various	Various				11
PJM OATT	Various	Various				12
PJM OATT	Various	Various				13
See footnote	Various	Various		38,045	38,045	14
						15
						16
						17
						18
						19
						20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
						32
						33
						34
			0	**38,045**	**38,045**	

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
2,334,985			2,334,985	1
13,019,495			13,019,495	2
253,346			253,346	3
5,553			5,553	4
18,420			18,420	5
847,441			847,441	6
621,335			621,335	7
	223,781		223,781	8
	36,642		36,642	9
84,377			84,377	10
		7,199	7,199	11
6,291			6,291	12
	8,650		8,650	13
		57,068	57,068	14
				15
				16
				17
				18
				19
				20
				21
				22
				23
				24
				25
				26
				27
				28
				29
				30
				31
				32
				33
				34
17,191,243	**269,073**	**64,267**	**17,524,583**	

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	04/11/2014	2013/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.: 11 Column: m

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

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

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

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

TRANSMISSION OF ELECTRICITY BY ISO/RTOs

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	LFP	123,851	123,851			185,776	185,776
2	East KY Power Coop							
3	PJM - Enhancements	OS					3,617,808	3,617,808
4	PJM - NITS	OS					2,885,758	2,885,758
5	PJM - Trans Owner	OS					13,493	13,493
6								
7	Other	OS					61	61
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		123,851	123,851			6,702,896	6,702,896

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	04/11/2014	2013/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. 1530, the Interconnection Agreement between AEPSC and East Kentucky Power Cooperative.

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

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

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

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

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

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

Schedule Page: 332 Line No.: 7 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	04/11/2014	End of 2013/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	77,922
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	3,453
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	281,150
7	AEP Service Corporation Billings	98,818
8	Intercompany Billings (Net)	-59,332
9	Corporate Money Pool Allocations	9,647
10	Employee Death Benefits	10,600
11	Miscellaneous	951
12		
13		
14		
15		
16		
17		
18		
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
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34		
35		
36		
37		
38		
39		
40		
41		
42		
43		
44		
45		
46	TOTAL	431,209

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,173,610		3,173,610
2	Steam Production Plant	20,384,410		457,126		20,841,536
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	8,716,316				8,716,316
8	Distribution Plant	23,769,486				23,769,486
9	Regional Transmission and Market Operation					
10	General Plant	850,603		54,054		904,657
11	Common Plant-Electric					
12	TOTAL	53,720,815		3,684,790		57,405,605

B. Basis for Amortization Charges

Section A, Line 1, Column D represents amortization of franchises over the life of the franchise ($487) and amortization of capitalized software development costs over a 5 year life ($3,173,123)

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) = ($68,025)

Total = ($457,126)

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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	540,198					
13	TRANSMISSION PLANT	493,685					
14	DISTRIBUTION PLANT	685,643					
15	GENERAL PLANT	33,759					
16	DEPRECIABLE SUM	1,753,285					
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
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47							
48							
49							
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	04/11/2014	2013/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, 2013 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	04/11/2014	End of 2013/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	2013 Kentucky Power Base Case		139,228	139,228	
2	KPSC - Case No. 2013-00197				
3					
4	2013 Integrated Resource Planning		73,355	73,355	
5	KPSC - Case No. 2013-00475				
6					
7	Transfer of 50% Interest in Mitchell Plant		47,208	47,208	
8	KPSC - Case No. 2012-00578				
9					
10	Miscellaneous		6,787	6,787	
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		266,578	266,578	

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	119,612					1
							2
							3
	928	73,355					4
							5
							6
	928	47,208					7
							8
							9
	928	26,403					10
							11
							12
							13
							14
							15
							16
							17
							18
							19
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							22
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							44
							45
		266,578					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	04/11/2014	End of 2013/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	5 items under $50,000
2		
3	A(1)e: Generation: Unconventional	4 items under $50,000
4		
5	A(2): Transmission	3 items under $50,000
6		
7	A(3): Distribution	2 items under $50,000
8		
9	A(5): Environment (other than equipment)	Carbon Management - University of Kentucky Research Foundation
10		3 items under $50,000
11		
12	A(6): Other	6 items under $50,000
13		
14	A(6)g: Other (program management)	1 item under $50,000
15		
16	B(1): R&D support to the Research Council	EPRI Environmental Science
17	or the Electric Power Research	EPRI Research Portfolio
18	Institute	30 items under $50,000
19		
20	B(4): Research to support others	5 items under $50,000
21		
22		
23		
24		
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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)	Amount (f)	Unamortized Accumulation (g)	Line No.
16,244		506	16,244		1
					2
515		506, 588	515		3
					4
1,868		566	1,868		5
					6
1,440		588	1,440		7
					8
200,000		182.3	200,000		9
6,879		506	6,879		10
					11
9,192		Various	9,192		12
					13
1,392		Various	1,392		14
					15
	87,065	506	87,065		16
	111,727	Various	111,727		17
	39,985	Various	39,985		18
					19
	17,097	566, 588	17,097		20
					21
					22
					23
					24
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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	04/11/2014	End of 2013/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	3,091,576		
4	Transmission	237,279		
5	Regional Market			
6	Distribution	2,846,908		
7	Customer Accounts	1,284,344		
8	Customer Service and Informational	581,474		
9	Sales			
10	Administrative and General	916,801		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	8,958,382		
12	Maintenance			
13	Production	3,967,144		
14	Transmission	766,261		
15	Regional Market			
16	Distribution	4,309,852		
17	Administrative and General	497,397		
18	TOTAL Maintenance (Total of lines 13 thru 17)	9,540,654		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	7,058,720		
21	Transmission (Enter Total of lines 4 and 14)	1,003,540		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	7,156,760		
24	Customer Accounts (Transcribe from line 7)	1,284,344		
25	Customer Service and Informational (Transcribe from line 8)	581,474		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	1,414,198		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	18,499,036	1,039,574	19,538,610
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	04/11/2014	End of 2013/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)	18,499,036	1,039,574	19,538,610
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	10,953,420	615,539	11,568,959
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	10,953,420	615,539	11,568,959
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,172,810	122,103	2,294,913
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,172,810	122,103	2,294,913
77	Other Accounts (Specify, provide details in footnote):			
78	152 - Fuel Stock Undistributed	1,241,669		1,241,669
79	163 - Stores Expense Undistributed	1,037,194	-1,037,194	
80	183 - Prelim Survey	1,211	-1,211	
81	184 - Clearing Accounts	738,811	-738,811	
82	185 - ODD Temporary Facilities	38,577		38,577
83	186 - Misc Deferred Debits	-12,418		-12,418
84	188 - Research & Development	-162		-162
85	426 - Political Activities	33,237		33,237
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,078,119	-1,777,216	1,300,903
96	TOTAL SALARIES AND WAGES	34,703,385		34,703,385

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	04/11/2014	2013/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	04/11/2014	End of 2013/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.

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)				19,063,116
3	Net Sales (Account 447)				(68,675,845)
4	Transmission Rights				(3,615,946)
5	Ancillary Services				4,651,054
6	Other Items (list separately)				
7	Congestion				7,883,544
8	Operating Reserves				(3,730,065)
9	Transmission Purchase Expense				663,497
10	Transmission Losses				9,904,055
11	Meter Corrections				(118,954)
12	Inadvertent				(55,505)
13	Capacity Credits				(367,494)
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
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43					
44					
45					
46	TOTAL				(34,398,543)

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	04/11/2014	End of 2013/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
Kentucky Power Company	(1) X An Original (2) _ A Resubmission	04/11/2014	2013/Q4

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.

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	04/11/2014	End of 2013/Q4

MONTHLY TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Columns (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (j) by month the system' monthly maximum megawatt load by statistical classifications. See General Instruction for the definition of each statistical classification.

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Firm Network Service for Self (e)	Firm Network Service for Others (f)	Long-Term Firm Point-to-point Reservations (g)	Other Long-Term Firm Service (h)	Short-Term Firm Point-to-point Reservation (i)	Other Service (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

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	04/11/2014	2013/Q4

FOOTNOTE DATA

Schedule Page: 400 Line No.: 1 Column: b

Kentucky Power Company's transmission service is administered through an RTO/ISO and requested information is not available on an individual operating company basis.

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	04/11/2014	End of 2013/Q4

MONTHLY ISO/RTO TRANSMISSION SYSTEM PEAK LOAD

(1) Report the monthly peak load on the respondent's transmission system. If the Respondent has two or more power systems which are not physically integrated, furnish the required information for each non-integrated system.
(2) Report on Column (b) by month the transmission system's peak load.
(3) Report on Column (c) and (d) the specified information for each monthly transmission - system peak load reported on Column (b).
(4) Report on Columns (e) through (i) by month the system's transmission usage by classification. Amounts reported as Through and Out Service in Column (g) are to be excluded from those amounts reported in Columns (e) and (f).
(5) Amounts reported in Column (j) for Total Usage is the sum of Columns (h) and (i).

NAME OF SYSTEM:

Line No.	Month (a)	Monthly Peak MW - Total (b)	Day of Monthly Peak (c)	Hour of Monthly Peak (d)	Imports into ISO/RTO (e)	Exports from ISO/RTO (f)	Through and Out Service (g)	Network Service Usage (h)	Point-to-Point Service Usage (i)	Total Usage (j)
1	January									
2	February									
3	March									
4	Total for Quarter 1									
5	April									
6	May									
7	June									
8	Total for Quarter 2									
9	July									
10	August									
11	September									
12	Total for Quarter 3									
13	October									
14	November									
15	December									
16	Total for Quarter 4									
17	Total Year to Date/Year									

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/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)	Line No.	Item (a)	MegaWatt Hours (b)
1	SOURCES OF ENERGY		21	DISPOSITION OF ENERGY	
2	Generation (Excluding Station Use):		22	Sales to Ultimate Consumers (Including Interdepartmental Sales)	6,537,521
3	Steam	2,764,447			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	94,128
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	3,301,878
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	2,764,447	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	7,600,111	27	Total Energy Losses	431,031
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	10,364,558
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	38,045			
17	Delivered	38,045			
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)	10,364,558			

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	04/11/2014	End of 2013/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	Total Monthly Energy	Monthly Non-Requirments Sales for Resale & Associated Losses	MONTHLY PEAK		
				Megawatts (See Instr. 4)	Day of Month	Hour
	(a)	(b)	(c)	(d)	(e)	(f)
29	January	1,058,962	356,688	1,409	23	800
30	February	886,392	262,506	1,315	1	900
31	March	968,630	320,888	1,293	22	700
32	April	775,046	258,741	1,128	3	700
33	May	662,263	158,214	1,021	31	1600
34	June	770,909	215,262	1,124	12	1600
35	July	929,032	352,898	1,137	18	1600
36	August	940,209	381,021	1,097	28	1600
37	September	806,515	313,229	1,084	10	1600
38	October	691,692	181,389	978	26	800
39	November	746,342	138,311	1,194	13	700
40	December	1,128,566	467,829	1,274	13	800
41	TOTAL	10,364,558	3,406,976			

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	04/11/2014	End of 2013/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)	1081	0
7	Plant Hours Connected to Load	6345	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	2764447000	0
13	Cost of Plant: Land and Land Rights	1753939	0
14	Structures and Improvements	43291665	0
15	Equipment Costs	505349022	0
16	Asset Retirement Costs	3614563	0
17	Total Cost	554009189	0
18	Cost per KW of Installed Capacity (line 17/5) Including	505.1141	0
19	Production Expenses: Oper, Supv, & Engr	1797648	0
20	Fuel	98562706	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	2941411	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	399129	0
26	Misc Steam (or Nuclear) Power Expenses	4304473	0
27	Rents	900	0
28	Allowances	5803450	0
29	Maintenance Supervision and Engineering	1821917	0
30	Maintenance of Structures	872830	0
31	Maintenance of Boiler (or reactor) Plant	6565943	0
32	Maintenance of Electric Plant	2995792	0
33	Maintenance of Misc Steam (or Nuclear) Plant	578915	0
34	Total Production Expenses	126645114	0
35	Expenses per Net KWh	0.0458	0.0000

Line No.	Item (a)	(b)	(b)	(b)	(c)	(c)	(c)
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	1085619	20130	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	11679	136942	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	82.861	128.599	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	88.384	129.743	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	3.784	22.558	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.035	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9211.000	0.000	0.000	0.000	0.000	0.000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

STEAM-ELECTRIC GENERATING PLANT STATISTICS (Large Plants)*(Continued)*

9. Items under Cost of Plant are based on U. S. of A. Accounts. Production expenses do not include Purchased Power, System Control and Load Dispatching, and Other Expenses Classified as Other Power Supply Expenses. 10. For IC and GT plants, report Operating Expenses, Account Nos. 547 and 549 on Line 25 "Electric Expenses," and Maintenance Account Nos. 553 and 554 on Line 32, "Maintenance of Electric Plant." Indicate plants designed for peak load service. Designate automatically operated plants. 11. For a plant equipped with combinations of fossil fuel steam, nuclear steam, hydro, internal combustion or gas-turbine equipment, report each as a separate plant. However, if a gas-turbine unit functions in a combined cycle operation with a conventional steam unit, include the gas-turbine with the steam plant. 12. If a nuclear power generating plant, briefly explain by footnote (a) accounting method for cost of power generated including any excess costs attributed to research and development; (b) types of cost units used for the various components of fuel cost; and (c) any other informative data concerning plant type fuel used, fuel enrichment type and quantity for the report period and other physical and operating characteristics of plant.

Plant Name: (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

(d)	(d)	(d)	(e)	(e)	(e)	(f)	(f)	(f)	Line No.
									36
									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
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants)

1. Large plants are hydro plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. If licensed project, give project number.
3. If net peak demand for 60 minutes is not available, give that which is available specifying period.
4. If a group of employees attends more than one generating plant, report on line 11 the approximate average number of employees assignable to each plant.

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)	FERC Licensed Project No. 0 Plant Name: (c)
1	Kind of Plant (Run-of-River or Storage)		
2	Plant Construction type (Conventional or Outdoor)		
3	Year Originally Constructed		
4	Year Last Unit was Installed		
5	Total installed cap (Gen name plate Rating in MW)	0.00	0.00
6	Net Peak Demand on Plant-Megawatts (60 minutes)	0	0
7	Plant Hours Connect to Load	0	0
8	Net Plant Capability (in megawatts)		
9	(a) Under Most Favorable Oper Conditions	0	0
10	(b) Under the Most Adverse Oper Conditions	0	0
11	Average Number of Employees	0	0
12	Net Generation, Exclusive of Plant Use - Kwh	0	0
13	Cost of Plant		
14	Land and Land Rights	0	0
15	Structures and Improvements	0	0
16	Reservoirs, Dams, and Waterways	0	0
17	Equipment Costs	0	0
18	Roads, Railroads, and Bridges	0	0
19	Asset Retirement Costs	0	0
20	TOTAL cost (Total of 14 thru 19)	0	0
21	Cost per KW of Installed Capacity (line 20 / 5)	0.0000	0.0000
22	Production Expenses		
23	Operation Supervision and Engineering	0	0
24	Water for Power	0	0
25	Hydraulic Expenses	0	0
26	Electric Expenses	0	0
27	Misc Hydraulic Power Generation Expenses	0	0
28	Rents	0	0
29	Maintenance Supervision and Engineering	0	0
30	Maintenance of Structures	0	0
31	Maintenance of Reservoirs, Dams, and Waterways	0	0
32	Maintenance of Electric Plant	0	0
33	Maintenance of Misc Hydraulic Plant	0	0
34	Total Production Expenses (total 23 thru 33)	0	0
35	Expenses per net KWh	0.0000	0.0000

HYDROELECTRIC GENERATING PLANT STATISTICS (Large Plants) (Continued)

5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power, System control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."
6. Report as a separate plant any plant equipped with combinations of steam, hydro, internal combustion engine, or gas turbine equipment.

FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	FERC Licensed Project No. 0 Plant Name: (f)	Line No.
			1
			2
			3
			4
0.00	0.00	0.00	5
0	0	0	6
0	0	0	7
			8
0	0	0	9
0	0	0	10
0	0	0	11
0	0	0	12
			13
0	0	0	14
0	0	0	15
0	0	0	16
0	0	0	17
0	0	0	18
0	0	0	19
0	0	0	20
0.0000	0.0000	0.0000	21
			22
0	0	0	23
0	0	0	24
0	0	0	25
0	0	0	26
0	0	0	27
0	0	0	28
0	0	0	29
0	0	0	30
0	0	0	31
0	0	0	32
0	0	0	33
0	0	0	34
0.0000	0.0000	0.0000	35

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants)

1. Large plants and pumped storage plants of 10,000 Kw or more of installed capacity (name plate ratings)
2. If any plant is leased, operating under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, indicate such facts in a footnote. Give project number.
3. If net peak demand for 60 minutes is not available, give the which is available, specifying period.
4. If a group of employees attends more than one generating plant, report on line 8 the approximate average number of employees assignable to each plant.
5. The items under Cost of Plant represent accounts or combinations of accounts prescribed by the Uniform System of Accounts. Production Expenses do not include Purchased Power System Control and Load Dispatching, and Other Expenses classified as "Other Power Supply Expenses."

Line No.	Item (a)	FERC Licensed Project No. 0 Plant Name: (b)
1	Type of Plant Construction (Conventional or Outdoor)	
2	Year Originally Constructed	
3	Year Last Unit was Installed	
4	Total installed cap (Gen name plate Rating in MW)	
5	Net Peak Demaind on Plant-Megawatts (60 minutes)	
6	Plant Hours Connect to Load While Generating	
7	Net Plant Capability (in megawatts)	
8	Average Number of Employees	
9	Generation, Exclusive of Plant Use - Kwh	
10	Energy Used for Pumping	
11	Net Output for Load (line 9 - line 10) - Kwh	
12	Cost of Plant	
13	Land and Land Rights	
14	Structures and Improvements	
15	Reservoirs, Dams, and Waterways	
16	Water Wheels, Turbines, and Generators	
17	Accessory Electric Equipment	
18	Miscellaneous Powerplant Equipment	
19	Roads, Railroads, and Bridges	
20	Asset Retirement Costs	
21	Total cost (total 13 thru 20)	
22	Cost per KW of installed cap (line 21 / 4)	
23	Production Expenses	
24	Operation Supervision and Engineering	
25	Water for Power	
26	Pumped Storage Expenses	
27	Electric Expenses	
28	Misc Pumped Storage Power generation Expenses	
29	Rents	
30	Maintenance Supervision and Engineering	
31	Maintenance of Structures	
32	Maintenance of Reservoirs, Dams, and Waterways	
33	Maintenance of Electric Plant	
34	Maintenance of Misc Pumped Storage Plant	
35	Production Exp Before Pumping Exp (24 thru 34)	
36	Pumping Expenses	
37	Total Production Exp (total 35 and 36)	
38	Expenses per KWh (line 37 / 9)	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	04/11/2014	End of 2013/Q4

PUMPED STORAGE GENERATING PLANT STATISTICS (Large Plants) (Continued)

6. Pumping energy (Line 10) is that energy measured as input to the plant for pumping purposes.
7. Include on Line 36 the cost of energy used in pumping into the storage reservoir. When this item cannot be accurately computed leave Lines 36, 37 and 38 blank and describe at the bottom of the schedule the company's principal sources of pumping power, the estimated amounts of energy from each station or other source that individually provides more than 10 percent of the total energy used for pumping, and production expenses per net MWH as reported herein for each source described. Group together stations and other resources which individually provide less than 10 percent of total pumping energy. If contracts are made with others to purchase power for pumping, give the supplier contract number, and date of contract.

FERC Licensed Project No. 0 Plant Name: (c)	FERC Licensed Project No. 0 Plant Name: (d)	FERC Licensed Project No. 0 Plant Name: (e)	Line No.
			1
			2
			3
			4
			5
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			23
			24
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			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	04/11/2014	End of 2013/Q4

GENERATING PLANT STATISTICS (Small Plants)

1. Small generating plants are steam plants of, less than 25,000 Kw; internal combustion and gas turbine-plants, conventional hydro plants and pumped storage plants of less than 10,000 Kw installed capacity (name plate rating). 2. Designate any plant leased from others, operated under a license from the Federal Energy Regulatory Commission, or operated as a joint facility, and give a concise statement of the facts in a footnote. If licensed project, give project number in footnote.

Line No.	Name of Plant (a)	Year Orig. Const. (b)	Installed Capacity Name Plate Rating (In MW) (c)	Net Peak Demand MW (60 min.) (d)	Net Generation Excluding Plant Use (e)	Cost of Plant (f)
1						
2						
3						
4						
5						
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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	04/11/2014	End of 2013/Q4

GENERATING PLANT STATISTICS (Small Plants) (Continued)

3. List plants appropriately under subheadings for steam, hydro, nuclear, internal combustion and gas turbine plants. For nuclear, see instruction 11, Page 403. 4. If net peak demand for 60 minutes is not available, give the which is available, specifying period. 5. If any plant is equipped with combinations of steam, hydro internal combustion or gas turbine equipment, report each as a separate plant. However, if the exhaust heat from the gas turbine is utilized in a steam turbine regenerative feed water cycle, or for preheated combustion air in a boiler, report as one plant.

Plant Cost (Incl Asset Retire. Costs) Per MW (g)	Operation Exc'l. Fuel (h)	Production Expenses Fuel (i)	Production Expenses Maintenance (j)	Kind of Fuel (k)	Fuel Costs (in cents (per Million Btu) (l)	Line No.
						1
						2
						3
						4
						5
						6
						7
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						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	04/11/2014	End of 2013/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 (Pole miles) On Structures of Another Line (g)	Number Of Circuits (h)
1	0700 BIG SANDY, KY	AMOS WV	765.00	765.00	ST	0.13		1
2	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	ALUM	24.20		1
3	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	ST	4.79		1
4	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ALUM	12.65		1
5	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ST	3.04		1
6	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ALUMT	58.26		1
7	0703 HANGING ROCK, OH	JEFFERSON, IN	765.00	765.00	ST	154.74		1
8	0300 BIG SANDY, KY	TRI-STATE, WV	345.00	345.00	ST	8.36		1
9	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	WP	45.62		1
10	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	ST	0.72		1
11	0135 WOOTEN	ARNOLD DELVINTA (LGE)	161.00	161.00	WP	1.09		1
12	0136 WOOTEN EXTENSION		161.00	161.00	ST			1
13	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	ALUM	12.08		1
14	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	ST	14.77		1
15	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	ST	0.33		1
16	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	ST	1.10	1.10	1
17	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	5.91		1
18	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	23.25		1
19	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	ST	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
36					TOTAL	1,241.09	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	04/11/2014	End of 2013/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	Line cost and expense are	not available by individual						
34	transmission line	Total shown in Column j - p						
35								
36					TOTAL	1,241.09	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	04/11/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
954 MCMA								1
954 MCMA								2
								3
954 MCMA								4
								5
								6
351.5 VAR								7
954 MCMA								8
500 MCMCU								9
								10
795 MCM 26/7								11
795 MCM 26/7								12
556.5 VAR								13
								14
1033.5 VAR								15
397.5 MA								16
397.5 MCMCU								17
								18
636 MCMA								19
								20
397 MCMA								21
397.5 MCMA								22
								23
								24
795 MCMA								25
								26
795 MCMA								27
795 MCMA								28
								29
556.5 MCM								30
795 MCMA								31
1590 KCM								32
1033 MCM								33
10335 VAR								34
10335 VAR								35
	28,186,094	291,236,316	319,422,410	119,543	1,773,834		1,893,377	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	04/11/2014	End of 2013/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way) Land (j)	Construction and Other Costs (k)	Total Cost (l)	EXPENSES, EXCEPT DEPRECIATION AND TAXES Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	Line No.
10335 VAR								1
795 MCMA								2
795 MCMA								3
397 MCMA								4
10335 VAR								5
								6
795 ACSR								7
1033 MCM								8
1351 KCM								9
2-556.5 MCM								10
1033 MCM								11
								12
795 ACSR								13
1590 ACSR								14
1590 ACSR								15
795 ACSR								16
795 ACSR								17
								18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
	28,186,094	291,236,316	319,422,410	119,543	1,773,834		1,893,377	33
								34
								35
	28,186,094	291,236,316	319,422,410	119,543	1,773,834		1,893,377	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	04/11/2014	End of 2013/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							
4							
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
16							
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31							
32							
33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL						

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).
3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage	LINE COST					Line
Size (h)	Specification (i)	Configuration and Spacing (j)	KV (Operating) (k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	No.
									1
									2
									3
									4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
									17
									18
									19
									20
									21
									22
									23
									24
									25
									26
									27
									28
									29
									30
									31
									32
									33
									34
									35
									36
									37
									38
									39
									40
									41
									42
									43
									44

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		
14	BECKHAM-KY	D	138.00	34.50	
15		D	138.00		
16	BEEFHIDE-KY	D	138.00	34.50	
17	BELFRY-KY	D	46.00	12.00	
18	BELHAVEN-KY	D	138.00	13.09	
19	BELLEFONTE-KY	T	138.00	69.00	34.50
20		T	138.00	35.00	
21		T	138.00	13.09	
22		T	69.00		
23	BETSY LAYNE-KY	T	138.00	69.00	46.00
24		T	138.00	34.00	
25		T	46.00	12.00	
26		T	46.00		
27	BIG SANDY 138KV-KY	T	138.00	69.50	13.20
28		T	138.00	34.50	
29		T	138.00	13.09	
30	BLUE GRASS-KY	D	69.00	12.00	
31	BONNYMAN-KY	T	138.00	70.50	13.00
32		T	69.00	34.50	
33	BUSSEYVILLE-KY	D	138.00	34.50	
34	CANNONSBURG-KY	D	69.00	34.50	
35	CEDAR CREEK-KY	T	138.00	69.00	46.00
36		T	138.00	34.50	
37		T	69.00	12.00	
38	CHADWICK-KY	T	138.00	69.00	34.50
39	COALTON-KY	D	69.00	12.00	
40		D	69.00		

SUBSTATIONS

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

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	HOODS CREEK-KY	D	69.00	12.00	
2	HOWARD COLLINS-KY	D	69.00	12.00	
3	INEZ-KY	T	138.00	69.00	13.09
4		T	138.00	37.27	13.80
5		T	138.00	37.00	
6		T	138.00		
7		T	138.00		
8		T	69.00		
9		T	26.00		
10		T	26.00	18.60	
11	JACKSON-KY	D	69.00	12.00	
12		D	69.00		
13	JENKINS-KY	D	69.00	12.00	
14	JOHNS CREEK-KY	T	138.00	69.00	34.00
15		T	138.00		
16		T	69.00		
17	KANAWHA RIVER-KY	D	46.00		
18		D	46.00	12.00	
19	KEYSER-KY	D	69.00	12.00	
20	LESLIE-KY	T	161.00	69.00	12.00
21		T	69.00	34.50	
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	

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	28 STATIONS UNDER 10 MVA	T/D			
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					

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.
22	1					1
			STATCAP	1	16	2
			REACTOR	2	200	3
1500	3					4
672	1					5
30		1				6
11		1				7
3		1				8
3		1				9
25	1					10
146	2					11
30	1					12
			STATCAP	4	235	13
30	1					14
			STATCAP	1	43	15
20	1					16
11	1					17
20	1					18
308	2					19
45	1					20
22	1					21
			STATCAP	1	14	22
50	1					23
25	1					24
6	1					25
			STATCAP	1	10	26
129	1					27
20	1					28
20	1					29
11	1					30
130	1					31
25	1					32
55	2					33
25	1					34
90	1					35
30		1				36
6		1				37
200	1					38
25	1					39
			STATCAP	1	23	40

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

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
11	1					1
31	2					2
50	1					3
160	1					4
320	2					5
			STATCAP	2	106	6
			UPFC	1		7
			STATCAP	1	10	8
86	1					9
86	1					10
15	2					11
			STATCAP	1	10	12
11	1					13
90	1					14
			STATCAP	1	53	15
			STATCAP	1	10	16
			STATCAP	1	7	17
20	1					18
20	1					19
90	1					20
30	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

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)	Number of Transformers In Service	Number of Spare Transformers	CONVERSION APPARATUS AND SPECIAL EQUIPMENT			Line No.
			Type of Equipment	Number of Units	Total Capacity (In MVa)	
(f)	(g)	(h)	(i)	(j)	(k)	
20	1					1
11	1					2
20	1					3
30	1					4
25	1					5
22	1	1				6
15	1					7
50	1					8
50	2					9
70	1					10
90	1					11
			STATCAP	1	32	12
			STATCAP	1	7	13
11	1					14
20	1					15
30	1					16
25	1	1				17
36	2					18
			STATCAP	1	13	19
20	1					20
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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	04/11/2014	End of 2013/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
1	**Non-power Goods or Services Provided by Affiliated**			
2	Administrative and General Expenses - Maintenance	AEPSC	935	547,348
3	Administrative and General Expenses - Operation	AEPSC	Various	1,970,139
4	Assets & Other Debits - Current and Accrued Assets	APCo	163	271,112
5	Assets & Other Debits - Utility Plant	APCo	107,108	645,043
6	Audit Services	AEPSC	920	284,624
7	Central Machine Shop	APCo	Various	686,520
8	Construction Services	AEPSC	107,108	10,633,454
9	Corporate Accounting	AEPSC	920	1,286,389
10	Corporate Planning and Budgeting	AEPSC	920	834,097
11	Customer Accounts Expenses	AEPSC	Various	3,252,094
12	Distribution Expenses	AEPSC	Various	1,129,894
13	Emission Allowance Purchases	APCo	158.1	1,585,761
14	Emission Allowance Purchases	OPCo	158.1	7,461,516
15	Factored Customer A/R Bad Debts	AEP Credit	426.5	1,175,163
16	Factored Customer A/R Expense	AEP Credit	426.5	829,600
17	Fleet and Vehicle Charges	APCo	Various	586,635
18	Fuel & Storeroom Services	AEPSC	151,152,163	840,638
19	Human Resources	AEPSC	920,923	522,696
20	**Non-power Goods or Services Provided for Affiliate**			
21	Assets and Other Debits - Utility Plant	APCo	107,108	583,070
22	Assets and Other Debits - Utility Plant	OHTCo	107	472,457
23	Assets and Other Debits - Utility Plant	OPCo	107,108	651,025
24	Building and Property Leases	AEPSC	454	255,911
25	Distribution Expenses - Maintenance	APCo	591-596	259,133
26	Fleet and Vehicle Charges	APCo	Various	470,972
27	Materials and Supplies	APCo	Various	2,152,272
28	Materials and Supplies	OPCo	Various	1,106,637
29	Transmission Expenses - Maintenance	OPCo	Various	285,380
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1	**Non-power Goods or Services Provided by Affiliated**			
2	Information Technology	AEPSC	920,923	1,173,941

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	04/11/2014	End of 2013/Q4

TRANSACTIONS WITH ASSOCIATED (AFFILIATED) COMPANIES

1. Report below the information called for concerning all non-power goods or services received from or provided to associated (affiliated) companies.
2. The reporting threshold for reporting purposes is $250,000. The threshold applies to the annual amount billed to the respondent or billed to an associated/affiliated company for non-power goods and services. The good or service must be specific in nature. Respondents should not attempt to include or aggregate amounts in a nonspecific category such as "general".
3. Where amounts billed to or received from the associated (affiliated) company are based on an allocation process, explain in a footnote.

Line No.	Description of the Non-Power Good or Service (a)	Name of Associated/Affiliated Company (b)	Account Charged or Credited (c)	Amount Charged or Credited (d)
3	Legal GC/Administration	AEPSC	920	861,448
4	Materials and Supplies	APCo	Various	3,060,855
5	Materials and Supplies	OPCo	Various	1,641,201
6	Other Power Generation - Maintenance	AEPSC	Various	1,289,767
7	Regulatory Services	AEPSC	920	1,023,471
8	Research and Other Services	AEPSC	Various	518,320
9	Steam Power Generation - Maintenance	AEPSC	510-514	884,506
10	Steam Power Generation - Operationg	AEPSC	Various	1,586,074
11	Transmission Expenses - Maintenance	AEPSC	Various	535,472
12	Transmission Expenses - Operation	AEPSC	Various	2,314,961
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20	**Non-power Goods or Services Provided for Affiliate**			
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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	04/11/2014	2013/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 fomulae that consider factors such as number of customers, number of employees, number of transmission miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for services are made at cost and include no compensation for a return on investment.

Schedule Page: 429 Line No.: 3 Column: c

920,921,923,924-926,928,930.1,930.2,931

Schedule Page: 429 Line No.: 7 Column: c

107,108,506,512,513,920

Schedule Page: 429 Line No.: 11 Column: c

901-903,905

Schedule Page: 429 Line No.: 12 Column: c

580-584,586,588

Schedule Page: 429 Line No.: 17 Column: c

Costs related to AEP's fleet vehicles are allocated in the same manner as the labor of each department utilizing the vehicles. To the extent a department provides service to another affiliate company, an applicable share of their fleet costs are also assigned to that affiliate company.

Schedule Page: 429 Line No.: 27 Column: c

107,108,154,163,512,513,570,571,588,592,593,935

Schedule Page: 429 Line No.: 28 Column: c

107,154,163,512,513,570,571,583,588,592,935

Schedule Page: 429 Line No.: 29 Column: c

568-571,573

Schedule Page: 429.1 Line No.: 4 Column: c

107,108,152,154,163,184,186,512,513,566,570,571,583,585-588,592-595,597,598,902,903,930

Schedule Page: 429.1 Line No.: 5 Column: c

107,108,154,163,184,186,502,512,566,569,570,585,592-595,903,921,930,935

Schedule Page: 429.1 Line No.: 6 Column: c

553,555-557

Schedule Page: 429.1 Line No.: 8 Column: c

183,184,186,188

Schedule Page: 429.1 Line No.: 10 Column: c

500-502,505,506

Schedule Page: 429.1 Line No.: 11 Column: c

568,569-569.3,570,571,573

Schedule Page: 429.1 Line No.: 12 Column: c

560,561.1,561.2,561.5,562,563,566

Schedule	Page No.

Schedule | Page No.

Schedule	Page No.

Filing Requirement
807 KAR 5:001 Section 16 (4)(n)

Filing Requirement:

A summary of the utility's latest depreciation study with schedules by major plant accounts, except that telecommunications utilities that have adopted the commission's average depreciation rates shall provide a schedule that identifies the current and test period depreciation rates used by major plant accounts. If the required information has been filed in another commission case, a reference to that case's number shall be sufficient;

Response:

A summary of the Company's most recent depreciation study, along with a copy of the study itself, is contained in the testimony and exhibits of Company Witness Davis.

Filing Requirement
807 KAR 5:001 Section 16 (4)(o)

Filing Requirement:

A list of all commercially available or in-house developed computer software, programs, and models used in the development of the schedules and work papers associated with the filing of the utility's application. This list shall include each software, program, or model; what the software, program, or model was used for; identify the supplier of each software, program, or model; a brief description of the software, program, or model; and the specifications for the computer hardware and the operating system required to run the program;

Response:

- **PowerPlant software was used to perform certain tax calculations and perform the book depreciation studies of transmission; distribution and general plant were prepared using Version 9.0 of PowerPlant software. The software is the property of PowerPlan Consultants, Inc. of Atlanta, Georgia. AEP has a license with PowerPlan Consultants, Inc. to use the software. The computer operating system is Windows 7. The computer must have, at a minimum, 2.0 GHz PC with 1 GB of memory. The database is Oracle 11.2 and the database resides on UNIX AIX box.**

- **PowerTracker is used to perform settlement function of economically allocating generation and purchase resources to off-system sales transactions. It provides input to the monthly accounting and fuel clause reporting functions. PowerTracker is a Java application supplied by Integ Enterprise consulting. The current version of the application is aeptrack-app-v5.3.1-b696-r736-jcr1456. The application runs in a WebLogic version 10.0 environment. It is a multi-node environment consisting of three servers. The servers are Sun MicroSystems model SPARC Enterprise T5120 running the Solaris operating system v5.10, 32,640 MB RAM and 616 GB of Disk space. The database utilized by the application is Oracle version 11.2.0.3.0. The database runs on an IBM 9117-MMB server with 32,768 MB of RAM. Operating system is AIX. The supplier of PowerTracker is Integ Enterprise Consulting, Inc. located in Newark, New Jersey.**

- **nMarket is a modular application supplied by Ventyx, an ABB company. It is an integrated toolset that allows a participant to manage settlements with an ISO/RTO. It provides back-office support for settlement data capture, checkout, volume management, charge estimation and shadow settlement, and dispute management with the ISO/RTO. In addition to the core product, there is a security application (nMarket Security Manager) that must be installed as well. nMarket is a java application. The computer hardware server is a Dell PowerEdge R900 with Windows Server 2003. Additionally, the server is running virtualizing software**

manufactured by VMware, Inc. The model is VMware Virtual Platform. RAM is 3.72 MB.

- **Microsoft Excel. These applications were used to prepare spreadsheet documents utilized in this proceeding. The program was run on a laptop with 1 GB of RAM, and it is also run on desktops with 1 GB of RAM. The computer operating system is Microsoft Windows 7.**

- **Microsoft Word. These applications were the word processing software used to prepare the majority of the filings in this proceeding. The program was run on a laptop with 1 GB of RAM, and it is also run on desktops with 1 GB of RAM. The computer operating system is Microsoft Windows 7.**

- **PeopleSoft General Ledger software is a vendor product from Oracle Corporation, Redwood Shores, California. Kentucky Power is using version 9.0 of this software. The software is owned by the Oracle corporation, but AEP has purchased our version of the application, with any "vendor support" being provided by Rimini Street, a 3rd party vendor support company. The software runs off a UNIX AIX server, using an Oracle 11.2 database. The computer workstations that access this application run on Windows 7 operating system, and require a minimum of 1 GB of memory and 1.73 GHz processor**

- **The UIPlanner Customer Revenue module was used to perform detailed rate design and analysis using customer billing data. The computer workstations that access this application run on Windows 7 operating system, and require a minimum of 1 GB of memory and 1.73 GHz processor.**

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	)	
A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

SECTION II

FILING REQUIREMENTS

VOLUME 3 OF 5

December 23, 2014

Filing Requirement
807 KAR 5:001 Section 16 (4)(p)

Filing Requirement:

Prospectuses of the most recent stock or bond offerings;

Response:

Please see the attached documents for the most recent offerings.

KENTUCKY POWER COMPANY

$120,000,000 4.18% Senior Notes, Series A, due September 30, 2026
$80,000,000 4.33% Senior Notes, Series B, due December 30, 2026

NOTE PURCHASE AGREEMENT

Dated as of July 10, 2014

TABLE OF CONTENTS

(Not a part of the Agreement)

**KENTUCKY POWER COMPANY
1 Riverside Plaza
Columbus, Ohio 43215**

$120,000,000 4.18% Senior Notes, Series A, due September 30, 2026
$80,000,000 4.33% Senior Notes, Series B, due December 30, 2026

Dated as of July 10, 2014

To Each of the Purchasers Listed in
SCHEDULE A HERETO:

Ladies and Gentlemen:

KENTUCKY POWER COMPANY, a Kentucky corporation (the *"Company"*), agrees with each of the Purchasers whose names appear at the end hereof as follows:

Section 1. AUTHORIZATION OF NOTES.

The Company will authorize the issue and sale of (a) $120,000,000 aggregate principal amount of its 4.18% Senior Notes, Series A, due September 30, 2026 (the *"Series A Notes"*) and (b) $80,000,000 aggregate principal amount of its 4.33% Senior Notes, Series B, due December 30, 2026 (the *"Series B Notes"*; the Series A Notes and the Series B Notes are hereinafter collectively referred to as the *"Notes,"* such term to include any such notes issued in substitution therefor pursuant to **Section 13**). The Notes shall be substantially in the form set out in **Exhibit 1-A** and **Exhibit 1-B**, respectively. Certain capitalized and other terms used in this Agreement are defined in **Schedule B**; and references to a "Schedule" or an "Exhibit" are, unless otherwise specified, to a Schedule or an Exhibit attached to this Agreement.

Section 2. SALE AND PURCHASE OF NOTES.

Subject to the terms and conditions of this Agreement, the Company will issue and sell to each Purchaser and each Purchaser will purchase from the Company, at the Closing provided for in **Section 3**, Notes in the principal amount and of the series specified opposite such Purchaser's name in **Schedule A** at the purchase price of 100% of the principal amount thereof. The Purchasers' obligations hereunder are several and not joint obligations and no Purchaser shall have any liability to any Person for the performance or non-performance of any obligation by any other Purchaser hereunder.

Section 3. CLOSINGS.

The sale and purchase of the Notes to be purchased by each Purchaser shall occur at the offices of Winston & Strawn LLP, 200 Park Avenue, New York, New York 10166, at 10:00 a.m. New York time, at two closings (each a *"Closing"* and respectively the *"First Closing"* and the *"Second Closing"*). The First Closing shall be on September 30, 2014 or on such other Business Day thereafter as may be agreed upon by the Company and the Purchasers purchasing the Notes sold at the First Closing. The Second Closing shall be on December 30, 2014 or on such other

Business Day thereafter as may be agreed upon by the Company and the Purchasers purchasing the Notes sold at the Second Closing. At each Closing, the Company will deliver to each Purchaser the Notes of the series to be purchased by such Purchaser in the form of a single Note for each series of the Notes to be purchased by such Purchaser (or such greater number of Notes in denominations of at least $100,000 as such Purchaser may request) dated the date of such Closing and registered in such Purchaser's name (or in the name of its nominee), against delivery by such Purchaser to the Company or its order of immediately available funds in the amount of the purchase price therefor by wire transfer of immediately available funds for the account of the Company to account number 40572089, account description: Kentucky Power Co. – Dist., at Citibank, N.A., 399 Park Avenue, New York, NY 10043, ABA No. 02100089. If at any Closing the Company shall fail to tender such Notes to any Purchaser as provided above in this **Section 3**, or any of the conditions specified in **Section 4** shall not have been fulfilled to such Purchaser's satisfaction, such Purchaser shall, at its election, be relieved of all further obligations under this Agreement, without thereby waiving any rights such Purchaser may have by reason of such failure or such nonfulfillment.

Section 4. Conditions to Closing.

Each Purchaser's obligation to purchase and pay for the Notes to be sold to such Purchaser at a Closing is subject to the fulfillment to such Purchaser's satisfaction, prior to or at such Closing, of the following conditions:

Section 4.1. Representations and Warranties. The representations and warranties of the Company in this Agreement shall be correct when made and at the time of such Closing.

Section 4.2. Performance; No Default. The Company shall have performed and complied with all agreements and conditions contained in this Agreement required to be performed or complied with by it prior to or at such Closing and from the date of this Agreement to such Closing assuming that Sections 9 and 10 are applicable from the date of this Agreement. From the date of this Agreement until such Closing, before and after giving effect to the issue and sale of the Notes (and the application of the proceeds thereof as contemplated by **Section 5.14**), no Default or Event of Default shall have occurred and be continuing. The Company shall not have entered into any transaction since the date of the Memorandum that would have been prohibited by **Section 10** had such Section applied since such date.

Section 4.3. Compliance Certificates.

(a) *Officer's Certificate*. The Company shall have delivered to such Purchaser an Officer's Certificate, dated the date of such Closing, certifying that the conditions specified in **Sections 4.1, 4.2** and **4.9** have been fulfilled.

(b) *Secretary's Certificate*. The Company shall have delivered to such Purchaser a certificate of its Secretary or Assistant Secretary, dated the date of such Closing, certifying as to (i) the resolutions attached thereto and other corporate proceedings relating to the authorization, execution and delivery of the Notes and this Agreement and (ii) the Company's organizational documents as then in effect.

Section 4.4. Opinions of Counsel. Such Purchaser shall have received opinions in form and substance satisfactory to such Purchaser, dated the date of such Closing (a) from internal counsel for American Electric Power Service Corporation, an affiliate of the Company, covering the matters set forth in **Exhibit 4.4(a)** and covering such other matters incident to the transactions contemplated hereby as such Purchaser or its counsel may reasonably request (and the Company hereby instructs its counsel to deliver such opinion to the Purchasers) and (b) from Winston & Strawn LLP, the Purchasers' special counsel in connection with such transactions, substantially in the form set forth in **Exhibit 4.4(b)** and covering such other matters incident to such transactions as such Purchaser may reasonably request.

Section 4.5. Purchase Permitted by Applicable Law, Etc. On the date of such Closing such Purchaser's purchase of Notes shall (a) be permitted by the laws and regulations of each jurisdiction to which such Purchaser is subject, without recourse to provisions (such as section 1405(a)(8) of the New York Insurance Law) permitting limited investments by insurance companies without restriction as to the character of the particular investment, (b) not violate any applicable law or regulation (including, without limitation, Regulation T, U or X of the Board of Governors of the Federal Reserve System) and (c) not subject such Purchaser to any tax, penalty or liability under or pursuant to any applicable law or regulation, which law or regulation was not in effect on the date hereof. If requested by such Purchaser, such Purchaser shall have received an Officer's Certificate certifying as to such matters of fact as such Purchaser may reasonably specify to enable such Purchaser to determine whether such purchase is so permitted.

Section 4.6. Sale of Other Notes. Contemporaneously with such Closing, the Company shall sell to each other Purchaser, and each other Purchaser shall purchase, the Notes to be purchased by it at such Closing as specified in **Schedule A**.

Section 4.7. Payment of Special Counsel Fees. Without limiting the provisions of **Section 15.1**, the Company shall have paid on or before such Closing the fees, charges and disbursements of the Purchasers' special counsel referred to in **Section 4.4** to the extent reflected in a statement of such counsel rendered to the Company at least two Business Days prior to such Closing.

Section 4.8. Private Placement Number. A Private Placement Number issued by Standard & Poor's CUSIP Service Bureau (in cooperation with the Securities Valuation Office of the National Association of Insurance Commissioners) shall have been obtained for each series of the Notes being sold at such Closing.

Section 4.9. Changes in Corporate Structure. The Company shall not have changed its jurisdiction of incorporation or organization, as applicable, or been a party to any merger or consolidation or succeeded to all or any substantial part of the liabilities of any other entity, at any time following the date of the most recent financial statements referred to in **Schedule 5.5**.

Section 4.10. Company Regulatory Approvals. Prior to the date of such Closing, any approval or consent of any regulatory body, state, federal or local, including, without limitation, any approval or consent required by the Kentucky Public Service Commission and the Federal Energy Regulatory Commission, required for the offer, issuance, sale and delivery of the Notes and the execution, delivery and performance by the Company of this Agreement and the Notes shall have been obtained, shall be in full force and effect, shall have not have been revoked or amended, shall not be the subject of a pending appeal and shall be legally sufficient to authorize the offer, issue and sale and delivery of the Notes and evidence of such approval or consent satisfactory to the Purchasers and their special counsel shall have been provided to them.

Section 4.11. Funding Instructions. At least three Business Days prior to the date of such Closing, each Purchaser purchasing Notes at such Closing shall have received written instructions signed by a Responsible Officer on letterhead of the Company confirming the information specified in **Section 3** including (a) the name and address of the transferee bank, (b) such transferee bank's ABA number and (c) the account name and number into which the purchase price for the Notes is to be deposited.

Section 4.12. Proceedings and Documents. All corporate and other proceedings in connection with the transactions contemplated by this Agreement and all documents and instruments incident to such transactions shall be satisfactory to such Purchaser and its special counsel, and such Purchaser and its special counsel shall have received all such counterpart originals or certified or other copies of such documents as such Purchaser or such special counsel may reasonably request.

Section 5. Representations and Warranties of the Company.

The Company represents and warrants to each Purchaser that:

Section 5.1. Organization; Power and Authority. The Company is a corporation duly organized, validly existing and in good standing under the laws of its jurisdiction of incorporation, and is duly qualified as a foreign corporation and is in good standing in each jurisdiction in which such qualification is required by law, other than those jurisdictions as to which the failure to be so qualified or in good standing would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect. The Company has the corporate power and authority to own or hold under lease the properties it purports to own or hold under lease, to transact the business it transacts and proposes to transact, to execute and deliver this Agreement and the Notes and to perform the provisions hereof and thereof.

Section 5.2. Authorization, Etc. This Agreement and the Notes have been duly authorized by all necessary corporate action on the part of the Company, and this Agreement constitutes, and upon execution and delivery thereof each Note will constitute, a legal, valid and binding obligation of the Company enforceable against the Company in accordance with its terms, except as such enforceability may be limited by (a) applicable bankruptcy, insolvency, reorganization, moratorium or other similar laws affecting the enforcement of creditors' rights generally and (b) general principles of equity (regardless of whether such enforceability is considered in a proceeding in equity or at law).

Section 5.3. Disclosure. The Company, through its agents, KeyBanc Capital Markets Inc. and RBS Securities Inc., has delivered to each Purchaser a copy of a Private Placement Memorandum, dated May/June 2014 (the "*Memorandum*"), relating to the transactions contemplated hereby. The Memorandum fairly describes, in all material respects, the general nature of the business and principal properties of the Company. This Agreement, the

Memorandum and the documents, certificates or other writings delivered to the Purchasers by or on behalf of the Company in connection with the transactions contemplated hereby and identified in **Schedule 5.3**, and the financial statements listed in **Schedule 5.5**, (this Agreement, the Memorandum and such documents, certificates or other writings and such financial statements delivered to each Purchaser prior to June 12, 2014 being referred to, collectively, as the *"Disclosure Documents"*), taken as a whole, do not contain any untrue statement of a material fact or omit to state any material fact necessary to make the statements therein not misleading in light of the circumstances under which they were made. Except as disclosed in the Disclosure Documents, since December 31, 2013, there has been no change in the financial condition, operations, business or properties of the Company except changes that individually or in the aggregate would not reasonably be expected to have a Material Adverse Effect. There is no fact known to the Company that would reasonably be expected to have a Material Adverse Effect that has not been set forth herein or in the Disclosure Documents.

Section 5.4. Directors and Senior Officers. **Schedule 5.4** contains (except as noted therein) a complete and correct list of the Company's directors and senior officers. The Company has no Subsidiaries.

Section 5.5. Financial Statements; Material Liabilities. The Company has delivered to each Purchaser copies of the financial statements of the Company listed on **Schedule 5.5**. All of said financial statements (including in each case the related schedules and notes) fairly present in all material respects the financial position of the Company as of the respective dates specified in such financial statements and the results of its operations and cash flows for the respective periods so specified and have been prepared in accordance with GAAP consistently applied throughout the periods involved except as set forth in the notes thereto (subject, in the case of any interim financial statements, to normal year-end adjustments). The Company does not have any Material liabilities that are not disclosed on such financial statements or otherwise disclosed in the Disclosure Documents.

Section 5.6. Compliance with Laws, Other Instruments, Etc. The execution, delivery and performance by the Company of this Agreement and the Notes will not (a) contravene, result in any breach of, or constitute a default under, or result in the creation of any Lien in respect of any property of the Company under, any Material indenture, mortgage, deed of trust, loan, purchase or credit agreement, lease, corporate charter or by-laws, or any other Material agreement or instrument to which the Company is bound or by which the Company or any of its properties may be bound or affected, (b) conflict with or result in a breach of any of the terms, conditions or provisions of any order, judgment, decree, or ruling of any court, arbitrator or Governmental Authority applicable to the Company or (c) violate any provision of any statute or other rule or regulation of any Governmental Authority applicable to the Company.

Section 5.7. Governmental Authorizations, Etc. No consent, approval or authorization of, or registration, filing or declaration with, any Governmental Authority is required in connection with the execution, delivery or performance by the Company of this Agreement or the Notes, other than (a) the authorization of the Kentucky Public Service Commission which authorization has been duly obtained pursuant to an order of the Kentucky Public Service Commission, which is in full force and effect, has not been revoked or amended, is not the subject of a pending appeal; the offer, issuance, sale and delivery of the Notes and the execution, delivery and performance by the Company of this Agreement and the Notes are in conformity with the terms of such order, (b) as may be required under state or foreign securities or blue sky laws, and (c) such registrations, filings and declarations that are not required to be made until after the date of such Closing and which will be made as and when required.

Section 5.8. Litigation; Observance of Agreements, Statutes and Orders. (a) There are no actions, suits, investigations or proceedings pending or, to the knowledge of the Company, threatened against or affecting the Company or any property of the Company in any court or before any arbitrator of any kind or before or by any Governmental Authority that, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect.

(b) The Company is not (i) in default under any agreement or instrument to which it is a party or by which it is bound, (ii) in violation of any order, judgment, decree or ruling of any court, arbitrator or Governmental Authority or (iii) in violation of any applicable law, ordinance, rule or regulation of any Governmental Authority (including, without limitation, Environmental Laws, the USA Patriot Act or any of the other laws and regulations that are referred to in **Section 5.16**), which default or violation, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect.

Section 5.9. Taxes. The Company has filed all tax returns that are required to have been filed in any jurisdiction, and have paid all taxes shown to be due and payable on such returns and all other taxes and assessments levied upon it or its properties, assets, income or franchises, to the extent such taxes and assessments have become due and payable and before they have become delinquent, except for any taxes and assessments (a) the amount of which is not individually or in the aggregate Material or (b) the amount, applicability or validity of which is currently being contested in good faith by appropriate proceedings and with respect to which the Company has established adequate reserves in accordance with GAAP. The Company knows of no basis for any other tax or assessment that would reasonably be expected to have a Material Adverse Effect. The charges, accruals and reserves on the books of the Company in respect of federal, state or other taxes for all fiscal periods are adequate in accordance with GAAP. The federal income tax liabilities of the Company have been finally determined (whether by reason of completed audits or the statute of limitations having run) for all fiscal years up to and including the fiscal year ended December 31, 2013.

Section 5.10. Title to Property; Leases. The Company has good and sufficient title to its properties that individually or in the aggregate are Material, including all such properties reflected in the most recent audited balance sheet referred to in **Section 5.5** or purported to have been acquired by the Company after said date (except as sold or otherwise disposed of in the ordinary course of business), in each case free and clear of Liens prohibited by this Agreement. All leases that individually or in the aggregate are Material are valid and subsisting and are in full force and effect in all material respects.

Section 5.11. Licenses, Permits, Etc. (a) The Company owns or possesses all licenses, permits, franchises, authorizations, patents, copyrights, proprietary software, service marks, trademarks and trade names, or rights thereto, that individually or in the aggregate are Material, without known conflict with the rights of others, the non-ownership or non-possession of which, individually or in the aggregate, would have a Material Adverse Effect.

(b) To the best knowledge of the Company, no product of the Company infringes in any Material respect any license, permit, franchise, authorization, patent, copyright, proprietary software, service mark, trademark, trade name or other right owned by any other Person which infringement, individually or in the aggregate would have a Material Adverse Effect.

(c) To the best knowledge of the Company, there is no Material violation by any Person of any right of the Company with respect to any patent, copyright, proprietary software, service mark, trademark, trade name or other right owned or used by the Company, which violation, individually or in the aggregate, would have a Material Adverse Effect.

Section 5.12. Compliance with ERISA. (a) The Company and each ERISA Affiliate have operated and administered each Plan in compliance with all applicable laws except for such instances of noncompliance as have not resulted in and could not, individually or in the aggregate, reasonably be expected to result in a Material Adverse Effect. Neither the Company nor any ERISA Affiliate has incurred any liability pursuant to Title I or IV of ERISA or the penalty or excise tax provisions of the Code relating to employee benefit plans (as defined in section 3 of ERISA), and no event, transaction or condition has occurred or exists that could, individually or in the aggregate, reasonably be expected to result in the incurrence of any such liability by the Company or any ERISA Affiliate, or in the imposition of any Lien on any of the rights, properties or assets of the Company or any ERISA Affiliate, in either case pursuant to Title I or IV of ERISA or to such penalty or excise tax provisions or to section 401(a)(29) or 412 of the Code, other than such liabilities or Liens as would not be individually or in the aggregate Material.

(b) For each of the Plans which are pension plans within the meaning of section 3(2) of ERISA (other than Multiemployer Plans) that are subject to the funding requirements of section 302 of ERISA or section 412 of the Code, **Schedule 5.12(b)** sets forth the funding target attainment percentage as of January 1, 2013, on the basis of the actuarial assumptions specified for funding purposes in such Plan's actuarial valuation report for the plan year beginning January 1, 2013. The term "funding target attainment percentage" has the meaning specified in section 303 of ERISA.

(c) The Company and its ERISA Affiliates have not incurred withdrawal liabilities (and are not subject to contingent withdrawal liabilities) under section 4201 or 4204 of ERISA in respect of Multiemployer Plans that individually or in the aggregate are Material.

(d) **Schedule 5.12(d)** sets forth the unfunded accumulated post retirement benefit obligation (APBO) as determined as of the last day of the Company's most recently ended fiscal year, December 31, 2013, in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 715-60 for retiree medical and life insurance plans, without regard to liabilities attributable to continuation coverage mandated by section 4980B of the Code, of the Company and such obligations would not, individually or in the aggregate, result in a Material Adverse Effect. The increase in such liabilities from December 31, 2013, to the date hereof is not Material and would not result in a Material Adverse Effect.

(e) The execution and delivery of this Agreement and the issuance and sale of the Notes hereunder will not involve any transaction that is subject to the prohibitions of section 406 of

ERISA or in connection with which a tax could be imposed pursuant to section 4975(c)(1)(A)-(D) of the Code. The representation by the Company in the first sentence of this **Section 5.12(e)** is made in reliance upon and subject to the accuracy of such Purchaser's representation in **Section 6.2** as to the sources of the funds used to pay the purchase price of the Notes to be purchased by such Purchaser and under the assumption that the parties identified to the Company pursuant to clauses (d), (e) and (g) thereof do not trigger issues with respect to the issuance and sale of the Notes to the parties described in those clauses.

Section 5.13. Private Offering by the Company. Neither the Company nor anyone acting on its behalf has offered the Notes or any similar securities for sale to, or solicited any offer to buy any of the same from, or otherwise approached or negotiated in respect thereof with, any Person other than the Purchasers and not more than 60 other Institutional Investors, each of which has been offered the Notes at a private sale for investment. Neither the Company nor anyone acting on its behalf has taken, or will take, any action that would subject the issuance or sale of the Notes to the registration requirements of Section 5 of the Securities Act or to the registration requirements of any securities or blue sky laws of any applicable jurisdiction.

Section 5.14. Use of Proceeds; Margin Regulations. The Company will apply the proceeds of the sale of the Notes as set forth in Section II.5 of the Memorandum. No part of the proceeds from the sale of the Notes hereunder will be used, directly or indirectly, for the purpose of buying or carrying any margin stock within the meaning of Regulation U of the Board of Governors of the Federal Reserve System (12 CFR 221), or for the purpose of buying or carrying or trading in any securities under such circumstances as to involve the Company in a violation of Regulation X of said Board (12 CFR 224) or to involve any broker or dealer in a violation of Regulation T of said Board (12 CFR 220). Margin Stock does not constitute more than 2% of the value of the assets of the Company and the Company does not have any present intention that Margin Stock will constitute more than 2% of the value of such assets.

Section 5.15. Existing Indebtedness; Future Liens. (a) **Schedule 5.15** sets forth a complete and correct list of all outstanding Indebtedness of the Company as of July 10, 2014 (including a description of the obligors and obligees, principal amount outstanding and collateral therefor, if any, and guarantee thereof, if any), since which date there has been no Material change in the amounts, interest rates, sinking funds, installment payments or maturities of the Indebtedness of the Company. The Company is not in default and no waiver of default is currently in effect, in the payment of any principal or interest on any Indebtedness of the Company, the outstanding principal amount of which exceeds $1,000,000, and no event or condition exists with respect to any Indebtedness of the Company, the outstanding principal amount of which exceeds $1,000,000, that would permit (or that with notice or the lapse of time, or both, would permit) one or more Persons to cause such Indebtedness to become due and payable before its stated maturity or before its regularly scheduled dates of payment and that, individually or in the aggregate, would reasonably be expected to have a Material Adverse Effect.

(b) Except as disclosed in **Schedule 5.15**, the Company has not agreed or consented to cause or permit any of its property, whether now owned or hereafter acquired, to be subject to a Lien that secures Indebtedness or to cause or permit in the future (upon the happening of a contingency or otherwise) any of its property, whether now owned or hereafter acquired, to be subject to a Lien not permitted by **Section 10.2**.

(c) Except as disclosed in **Schedule 5.15**, the Company is not a party to, or otherwise subject to any provision contained in, any instrument evidencing Indebtedness of the Company, any agreement relating thereto or any other agreement (including, but not limited to, its charter or other organizational document) which limits the amount of, or otherwise imposes restrictions on the incurring of, Indebtedness of the Company.

Section 5.16. Foreign Assets Control Regulations, Etc. (a) Neither the Company nor any Controlled Entity is (i) a Person whose name appears on the list of Specially Designated Nationals and Blocked Persons published by the Office of Foreign Assets Control, United States Department of the Treasury (*"OFAC"*) (an *"OFAC Listed Person"*) (ii) an agent, department, or instrumentality of, or is otherwise beneficially owned by, controlled by or acting on behalf of, directly or indirectly, (x) any OFAC Listed Person or (y) any Person, entity, organization, foreign country or regime that is subject to any OFAC Sanctions Program, or (iii) otherwise blocked, subject to sanctions under or engaged in any activity in violation of other United States economic sanctions, including but not limited to, the Trading with the Enemy Act, the International Emergency Economic Powers Act, the Comprehensive Iran Sanctions, Accountability and Divestment Act (*"CISADA"*) or any similar law or regulation with respect to Iran or any other country, the Sudan Accountability and Divestment Act, any OFAC Sanctions Program, or any economic sanctions regulations administered and enforced by the United States or any enabling legislation or executive order relating to any of the foregoing (collectively, *"U.S. Economic Sanctions"*) (each OFAC Listed Person and each other Person, entity, organization and government of a country described in clause (i), clause (ii) or clause (iii), a *"Blocked Person"*). Neither the Company nor any Controlled Entity has been notified that its name appears or may in the future appear on a state list of Persons that engage in investment or other commercial activities in Iran or any other country that is subject to U.S. Economic Sanctions.

(b) No part of the proceeds from the sale of the Notes hereunder constitutes or will constitute funds obtained on behalf of any Blocked Person or will otherwise be used by the Company or any Controlled Entity, directly or indirectly, (i) in connection with any investment in, or any transactions or dealings with, any Blocked Person, or (ii) otherwise in violation of U.S. Economic Sanctions.

(c) Neither the Company nor any Controlled Entity (i) has been found in violation of, charged with, or convicted of, money laundering, drug trafficking, terrorist-related activities or other money laundering predicate crimes under the Currency and Foreign Transactions Reporting Act of 1970 (otherwise known as the Bank Secrecy Act), the USA Patriot Act or any other United States law or regulation governing such activities (collectively, *"Anti-Money Laundering Laws"*) or any U.S. Economic Sanctions violations, (ii) to the Company's actual knowledge after making due inquiry, is under investigation by any Governmental Authority for possible violation of Anti-Money Laundering Laws or any U.S. Economic Sanctions violations, (iii) has been assessed civil penalties under any Anti-Money Laundering Laws or any U.S. Economic Sanctions, or (iv) has had any of its funds seized or forfeited in an action under any Anti-Money Laundering Laws. The Company has established procedures and controls which it reasonably believes are adequate (and otherwise comply with applicable law) to ensure that the

Company and each Controlled Entity is and will continue to be in compliance with all applicable current and future Anti-Money Laundering Laws and U.S. Economic Sanctions.

(d)(1) Neither the Company nor any Controlled Entity (i) has been charged with, or convicted of bribery or any other anti-corruption related activity under any applicable law or regulation in a U.S. or any non-U.S. country or jurisdiction, including but not limited to, the U.S. Foreign Corrupt Practices Act and the U.K. Bribery Act 2010 (collectively, *"Anti-Corruption Laws"*), (ii) to the Company's actual knowledge after making due inquiry, is under investigation by any U.S. or non-U.S. Governmental Authority for possible violation of Anti-Corruption Laws, (iii) has been assessed civil or criminal penalties under any Anti-Corruption Laws or (iv) has been or is the target of sanctions imposed by the United Nations or the European Union;

(2) To the Company's actual knowledge after making due inquiry, neither the Company nor any Controlled Entity has, within the last five years, directly or indirectly offered, promised, given, paid or authorized the offer, promise, giving or payment of anything of value to a Governmental Official or a commercial counterparty for the purposes of: (i) influencing any act, decision or failure to act by such Governmental Official in his or her official capacity or such commercial counterparty, (ii) inducing a Governmental Official to do or omit to do any act in violation of the Governmental Official's lawful duty, or (iii) inducing a Governmental Official or a commercial counterparty to use his or her influence with a government or instrumentality to affect any act or decision of such government or entity; in each case in order to obtain, retain or direct business or to otherwise secure an improper advantage; and

(3) No part of the proceeds from the sale of the Notes hereunder will be used, directly or indirectly, for any improper payments, including bribes, to any Governmental Official or commercial counterparty in order to obtain, retain or direct business or obtain any improper advantage. The Company has established procedures and controls which it reasonably believes are adequate (and otherwise comply with applicable law) to ensure that the Company and each Controlled Entity is and will continue to be in compliance with all applicable current and future Anti-Corruption Laws.

Section 5.17. Status under Certain Statutes. The Company is not subject to regulation under the Investment Company Act of 1940, as amended or the ICC Termination Act of 1995, as amended.

Section 5.18. Notes Rank Pari Passu. The payment obligations of the Company under this Agreement and the Notes rank at least *pari passu* in right of payment with all other unsecured Indebtedness (actual or contingent) of the Company, which is not expressed to be subordinate or junior in rank to any other unsecured Indebtedness of the Company, including, without limitation, all unsecured Indebtedness of the Company described in **Schedule 5.15** hereto.

Section 5.19. Environmental Matters. (a) The Company has no knowledge of any claim nor received any notice of any claim, and no proceeding has been instituted raising any claim against the Company or any of its real properties now or formerly owned, leased or operated by it or other assets, alleging any damage to the environment or violation of any Environmental

Laws, except, in each case, such as would not, individually or in the aggregate, reasonably be expected to result in a Material Adverse Effect.

(b) The Company has no knowledge of any facts which would give rise to any claim, public or private, of violation of Environmental Laws or damage to the environment emanating from, occurring on or in any way related to real properties now or formerly owned, leased or operated by it or to other assets or their use, except, in each case, such as would not reasonably be expected to result in a Material Adverse Effect.

(c) The Company has not stored any Hazardous Materials on real properties now or formerly owned, leased or operated by it nor has it disposed of any Hazardous Materials in a manner which is contrary to any Environmental Laws in each case in any manner that would, individually or in the aggregate, reasonably be expected to result in a Material Adverse Effect.

(d) All buildings on all real properties now owned, leased or operated by the Company are in compliance with applicable Environmental Laws, except where failure to comply would not reasonably be expected to result in a Material Adverse Effect.

Section 6. Representations of the Purchasers.

Section 6.1. Purchase for Investment. Each Purchaser severally represents that (a) it is purchasing the Notes for its own account or for one or more separate accounts maintained by such Purchaser or for the account of one or more pension or trust funds (each of which is an "accredited investor") as for each of which such Purchaser exercises sole investment discretion for investment purposes only and not with a view to the distribution thereof; *provided* that the re-sale or disposition of such Purchaser's or their property shall at all times be within such Purchaser's or their control, (b) it is an "accredited investor" (as defined in Rule 501(a)(1), (2), (3), (7) or (8) under the Securities Act), (c) it has such knowledge and experience in financial and business matters as to be capable of evaluating the merits and risks of an investment in the Notes, (d) it and any accounts for which it is acting are each able to bear the economic risk of its investments and (e) it has received adequate information concerning the Company and the Notes to make an informed investment decision with respect to the purchase of the Notes. Each Purchaser understands that the Notes have not been, and will not be, registered under the Securities Act (and that the Company is not required to register the Notes) and may be resold only (A) if registered pursuant to the provisions of the Securities Act, (B) if an exemption from registration is available, including, without limitation, by disposition of any of the Notes and then (i) to the Company; (ii) inside the United States to a "qualified institutional buyer" (as defined in Rule 144A under the Securities Act) in compliance with Rule 144A; (iii) inside the United States to an institutional investor that (1) is an "accredited investor" (as defined in Rule 501(a)(1), (2), (3), (7) or (8) under the Securities Act) and (2) makes the representations set forth in this **Section 6**; or (iv) outside the United States in compliance with Rule 904 under the Securities Act or (C) if resold under circumstances where neither such registration nor such exemption is required by law.

Each Purchaser agrees that, following the transfer of a Note and upon the request of the Company and without invalidating any transfer of any Note pursuant to this Agreement, it shall make reasonable best efforts to furnish to the Company any certificate which it may have received from any transferee of such Note with respect to such transferee's compliance with the terms of this **Section 6.1** in order to confirm that the transfer was made pursuant to an exemption from, or in a transaction not subject to, the registration requirements of the Securities Act.

Section 6.2. *Source of Funds*. Each Purchaser severally represents that at least one of the following statements is an accurate representation as to each source of funds (a *"Source"*) to be used by such Purchaser to pay the purchase price of the Notes to be purchased by such Purchaser hereunder:

(a) the Source is an "insurance company general account" (as the term is defined in the United States Department of Labor's Prohibited Transaction Exemption (*"PTE"*) 95-60) in respect of which the reserves and liabilities (as defined by the annual statement for life insurance companies approved by the National Association of Insurance Commissioners (the *"NAIC Annual Statement"*)) for the general account contract(s) held by or on behalf of any employee benefit plan together with the amount of the reserves and liabilities for the general account contract(s) held by or on behalf of any other employee benefit plans maintained by the same employer (or affiliate thereof as defined in PTE 95-60) or by the same employee organization in the general account do not exceed ten percent (10%) of the total reserves and liabilities of the general account (exclusive of separate account liabilities) plus surplus as set forth in the NAIC Annual Statement filed with such Purchaser's state of domicile; or

(b) the Source is a separate account that is maintained solely in connection with such Purchaser's fixed contractual obligations under which the amounts payable, or credited, to any employee benefit plan (or its related trust) that has any interest in such separate account (or to any participant or beneficiary of such plan (including any annuitant)) are not affected in any manner by the investment performance of the separate account; or

(c) the Source is either (i) an insurance company pooled separate account, within the meaning of PTE 90-1, or (ii) a bank collective investment fund, within the meaning of the PTE 91-38 and, except as have been disclosed by such Purchaser to the Company in writing pursuant to this clause (c), no employee benefit plan or group of plans maintained by the same employer or employee organization beneficially owns more than 10% of all assets allocated to such pooled separate account or collective investment fund; or

(d) the Source constitutes assets of an "investment fund" (within the meaning of Part VI of PTE 84-14 (the *"QPAM Exemption"*) managed by a "qualified professional asset manager" or "QPAM" (within the meaning of Part VI of the QPAM Exemption), no employee benefit plan's assets that are managed by the QPAM in such investment fund, when combined with the assets of all other employee benefit plans established or maintained by the same employer or by an affiliate (within the meaning of Part VI(c)(1) of the QPAM Exemption) of such employer or by the same employee organization and managed by such QPAM, represent more than 20% of the total client assets managed by such QPAM, the conditions of Part I(c) and (g) of the QPAM Exemption are satisfied, neither the QPAM nor a person controlling or controlled by the QPAM maintains an ownership interest in the Company that would cause the QPAM and the Company to be "related" within the meaning of Part VI(h) of the QPAM Exemption and (i) the identity of such QPAM and (ii) the names of any employee benefit plans whose assets in the investment fund, when combined with the assets of all other employee benefit plans established or maintained by the same employer or by an affiliate (within the meaning of Part VI(c)(1) of the QPAM Exemption) of such employer or by the same employee organization, represent 10% or more of the assets of such investment fund, have been disclosed to the Company in writing pursuant to this clause (d); or

(e) the Source constitutes assets of a "plan(s)" (within the meaning of Part IV(h) of PTE 96-23 (the *"INHAM Exemption"*)) managed by an "in-house asset manager" or "INHAM" (within the meaning of Part IV(a) of the INHAM Exemption), the conditions of Part I(a), (g) and (h) of the INHAM Exemption are satisfied, neither the INHAM nor a person controlling or controlled by the INHAM (applying the definition of "control" in Part IV(d)(3) of the INHAM Exemption) owns a 10% or more interest in the Company and (i) the identity of such INHAM and (ii) the name(s) of the employee benefit plan(s) whose assets constitute the Source have been disclosed to the Company in writing pursuant to this clause (e); or

(f) the Source is a governmental plan; or

(g) the Source is one or more employee benefit plans, or a separate account or trust fund comprised of one or more employee benefit plans, each of which has been identified to the Company in writing pursuant to this clause (g); or

(h) the Source does not include assets of any employee benefit plan, other than a plan exempt from the coverage of ERISA.

As used in this **Section 6.2**, the terms "employee benefit plan", "governmental plan", "party in interest" and "separate account" shall have the respective meanings assigned to such terms in section 3 of ERISA.

Section 7. Information as to the Company.

Section 7.1. Financial and Business Information. The Company shall deliver to each Purchaser and holder of Notes that is an Institutional Investor:

(a) *Quarterly Statements* — within 60 days after the end of each quarterly fiscal period in each fiscal year of the Company (other than the last quarterly fiscal period of each such fiscal year), duplicate copies of:

(i) a consolidated balance sheet of the Company as at the end of such quarter, and

(ii) consolidated statements of income, changes in shareholders' equity and cash flows of the Company for such quarter and (in the case of the second and third quarters) for the portion of the fiscal year ending with such quarter, setting forth in each case in comparative form the figures for the corresponding periods in the previous fiscal year, all in reasonable detail, prepared in accordance with GAAP applicable to quarterly financial statements generally, and certified by a Senior Financial Officer as fairly presenting, in all material respects, the financial position of the companies being reported on and their results of operations and cash flows, subject to changes resulting from year-end adjustments; *provided* that delivery within the time period specified above of copies of the Company's quarterly report containing substantially all the information required to be provided under this **Section 7.1(a)** shall be deemed to satisfy the requirements of this **Section 7.1(a)**;

(b) *Annual Statements* — within 105 days after the end of each fiscal year of the Company, duplicate copies of,

(i) a consolidated balance sheet of the Company, as at the end of such year, and

(ii) consolidated statements of income, changes in shareholders' equity and cash flows of the Company, for such year,

setting forth in each case in comparative form the figures for the previous fiscal year, all in reasonable detail, prepared in accordance with GAAP, and accompanied by an opinion thereon of independent public accountants of recognized national standing, which opinion shall state that such financial statements present fairly, in all material respects, the financial position of the companies being reported upon and their results of operations and cash flows and have been prepared in conformity with GAAP, and that the examination of such accountants in connection with such financial statements has been made in accordance with generally accepted auditing standards, and that such audit provides a reasonable basis for such opinion in the circumstances; *provided* that the delivery within the time period specified above of the Company's annual report for such fiscal year containing substantially all the information and the opinion of independent public accountants required to be provided under this **Section 7.1(b)** (together with the Company's annual report to shareholders, if any, prepared pursuant to Rule 14a-3 under the Exchange Act) shall be deemed to satisfy the requirements of this **Section 7.1(b)**;

(c) *SEC and Other Reports* — promptly upon their becoming available, one copy of (i) each financial statement, report, notice or proxy statement sent by the Company or any Subsidiary to its principal lending banks as a whole (excluding information sent to such banks in the ordinary course of administration of a bank facility, such as information relating to pricing and borrowing availability or to its public securities holders generally) and (ii) each regular or periodic report, each registration statement (without exhibits except as expressly requested by such holder), and each prospectus and all amendments thereto filed by the Company or any Subsidiary with the SEC and of all press releases and other statements made available generally by the Company or any Subsidiary to the public concerning developments that are Material; *provided, further,* that the Company should be deemed to have made such delivery of such SEC and other reports if it shall have timely made such SEC and other reports available via Electronic Delivery;

(d) *Notice of Default or Event of Default* — promptly, and in any event within five Business Days after a Responsible Officer becoming aware of the existence of any Default or Event of Default, a written notice specifying the nature and period of existence thereof and what action the Company is taking or proposes to take with respect thereto;

(e) *Notices from Governmental Authority* — promptly, and in any event within 30 days of receipt thereof, copies of any notice to the Company or any Subsidiary from any Federal or state Governmental Authority relating to any order, ruling, statute or other law or regulation that could reasonably be expected to have a Material Adverse Effect; and

(f) *Requested Information* — with reasonable promptness, such other data and information relating to the business, operations, affairs, financial condition, assets or properties of the Company or any of its Subsidiaries (including, but without limitation, actual copies of the Company's financial statements) or relating to the ability of the Company to perform its obligations hereunder and under the Notes as from time to time may be reasonably requested by any such Purchaser or holder of Notes.

Section 7.2. Officer's Certificate. Each set of financial statements delivered to a Purchaser or holder of Notes pursuant to **Section 7.1(a)** or **Section 7.1(b)** shall be accompanied by a certificate of a Senior Financial Officer setting forth:

(a) *Covenant Compliance* — the information (including detailed calculations) required in order to establish whether the Company was in compliance with the requirements of **Section 10.1** and **Section 10.2**, inclusive, during the quarterly or annual period covered by the statements then being furnished (including with respect to each such Section, where applicable, the calculations of the maximum or minimum amount, ratio or percentage, as the case may be, permissible under the terms of such Sections, and the calculation of the amount, ratio or percentage then in existence), and in the event that the Company has made an election to measure any financial liability using fair value (which election is being disregarded for purposes of determining compliance with this Agreement pursuant to **Section 22.3**) as to the period covered by any such financial statement, such Senior Financial Officer's certificate as to such period shall include a reconciliation from GAAP with respect to such election; and

(b) *Event of Default* — a statement that such Senior Financial Officer has reviewed the relevant terms hereof and has made, or caused to be made, under his or her supervision, a review of the transactions and conditions of the Company and its Subsidiaries from the beginning of the quarterly or annual period covered by the statements then being furnished to the date of the certificate and that such review shall not have disclosed the existence during such period of any condition or event that constitutes a Default or an Event of Default or, if any such condition or event existed or exists (including, without limitation, any such event or condition resulting from the failure of the Company or any Subsidiary to comply with any Environmental Law), specifying the nature and period of existence thereof and what action the Company shall have taken or proposes to take with respect thereto.

Section 7.3. Visitation. The Company shall permit the representatives of each Purchaser and holder of Notes that is an Institutional Investor:

(a) *No Default* — if no Default or Event of Default then exists, at the expense of such Purchaser or holder and upon reasonable prior notice to the Company, to visit the principal executive office of the Company, to discuss the affairs, finances and accounts of the Company and its Subsidiaries with the Company's officers, and (with the consent of the Company, which consent will not be unreasonably withheld) its independent public accountants, and (with the consent of the Company, which consent will not be unreasonably withheld) to visit the other offices and properties of the Company and each Subsidiary all at such reasonable times and as often as may be reasonably requested in writing; and

(b) *Default* — if a Default or Event of Default then exists, at the expense of the Company, to visit and inspect any of the offices or properties of the Company or any Subsidiary; to examine all their respective books of account, records, reports and other papers, to make copies and extracts therefrom, and to discuss their respective affairs, finances and accounts with their respective officers and independent public accountants (and by this provision the Company authorizes said accountants to discuss the affairs, finances and accounts of the Company and its Subsidiaries), all at such times and as often as may be requested.

Section 7.4. Electronic Delivery. Financial statements, opinions of independent certified public accountants, other information and Officer's Certificates that are required to be delivered by the Company pursuant to **Sections 7.1(a)**, **(b)** or **(c)** and **Section 7.2** shall be deemed to have been delivered if the Company satisfies any of the following requirements with respect thereto ("*Electronic Delivery*"):

(i) such financial statements satisfying the requirements of **Section 7.1(a)** or **(b)** and related Officer's Certificate satisfying the requirements of **Section 7.2** are delivered to each Purchaser or holder of a Note by e-mail;

(ii) the Company shall have timely filed such Form 10-Q or Form 10-K, satisfying the requirements of **Section 7.1(a)** or **Section 7.1(b)**, as the case may be, with the SEC on EDGAR and shall have made such form and the related Officer's Certificate satisfying the requirements of **Section 7.2** available on its home page on the internet, which is located at http://aep.com as of the date of this Agreement;

(iii) such financial statements satisfying the requirements of **Section 7.1(a)** or **Section 7.1(b)** and related Officer's Certificate(s) satisfying the requirements of **Section 7.2** are timely posted by or on behalf of the Company on IntraLinks or any other similar website (including the Company's home page located at http://aep.com) to which each Purchaser or holder of Notes has free access; or

(iv) the Company shall have filed any of the items referred to in **Section 7.1(c)** with the SEC on EDGAR and shall have made such items available on its home page on the internet or on IntraLinks or on any other similar website to which each Purchaser or holder of Notes has free access;

provided however, that upon request of any Purchaser or holder to receive paper copies of such forms, financial statements and Officer's Certificates or to receive them by e-mail, the Company will promptly e-mail them or deliver such paper copies, as the case may be, to such Purchaser or holder.

Section 8. ***PREPAYMENT OF THE NOTES.***

Section 8.1. *Maturity*. As provided therein, the entire unpaid principal balance of each series of the Notes shall be due and payable on the stated maturity date thereof.

Section 8.2. *Optional Prepayments with Make-Whole Amount*. (a) At any time prior to (i) in the case of the Series A Notes, 90 days prior to the stated maturity date of the Series A Notes, and (ii) in the case of the Series B Notes, 90 days prior to the stated maturity date of the Series B Notes, the Company may, at its option, upon notice as provided below, prepay at any time all, or from time to time any part of, the Notes of any series, in an amount not less than 10% of the aggregate principal amount of the Notes of such series then outstanding, at 100% of the principal amount so prepaid, together with interest accrued thereon to the date of such prepayment, and the Make-Whole Amount determined for the prepayment date with respect to such principal amount, and (b) at any time after (i) in the case of the Series A Notes, 90 days prior to the stated maturity date of the Series A Notes, and (ii) for the Series B Notes, 90 days prior to the stated maturity date of the Series B Notes, the Company may, at its option, upon notice as provided below, prepay at any time all, or from time to time any part of, the Notes of the relevant series, in an amount not less than 10% of the aggregate principal amount of the Notes of such series then outstanding, at 100% of the principal amount so prepaid, together with interest accrued thereon to the date of such prepayment; *provided* that if a Default or Event of Default shall have occurred and is continuing, in the case of a prepayment of less than all of the Notes, such partial prepayment shall be applied against each series of Notes in proportion to the aggregate principal amount outstanding of each series. The Company will give each holder of Notes written notice of each optional prepayment under this **Section 8.2** not less than 30 days and not more than 60 days prior to the date fixed for such prepayment unless the Company and the Required Holders agree to another time period pursuant to **Section 17**. Each such notice shall specify such date (which shall be a Business Day), the aggregate principal amount of each series of the Notes to be prepaid on such date, the principal amount of each Note held by such holder to be prepaid (determined in accordance with **Section 8.4**), and the interest to be paid on the prepayment date with respect to such principal amount being prepaid, and shall be accompanied by a certificate of a Senior Financial Officer as to the estimated Make-Whole Amount due in connection with such prepayment, if applicable (calculated as if the date of such notice were the date of the prepayment), setting forth the details of such computation. Two Business Days prior to such prepayment, the Company shall deliver to each holder of Notes a certificate of a Senior Financial Officer specifying the calculation of such Make-Whole Amount, if applicable, as of the specified prepayment date.

Section 8.3. *Change in Control*.

(a)Notice of Change in Control or Control Event. The Company will, within five Business Days after any Responsible Officer has knowledge of the occurrence of any Change in Control or Control Event, give written notice of such Change in Control or Control Event to each holder of Notes and apply to a Rating Agency for a review of the then applicable credit rating in respect of the Notes or other Rated Securities; it being understood that the Company will at the same time inform such Rating Agency of the Change in Control or Control Event.

(b)Notice of Change in Control Prepayment Event. The Company will, within five Business Days after any Responsible Officer has knowledge of the occurrence of any Change in Control Prepayment Event, give written notice of such Change in Control Prepayment Event to each holder of Notes and such notice shall contain and constitute an offer to prepay Notes as described in subparagraph (c) of this **Section 8.3** and shall be accompanied by the certificate described in subparagraph (f) of this **Section 8.3**.

(c)Offer to Prepay Notes. The offer to prepay Notes contemplated by subparagraph (b) of this **Section 8.3** shall be an offer to prepay, in accordance with and subject to this **Section 8.3**, all, but not less than all, the Notes held by each holder (in this case only, *"holder"* in respect of any Note registered in the name of a nominee for a disclosed beneficial owner shall mean such beneficial owner) on a date (which date shall be a Business Day) specified in such offer (the *"Proposed Prepayment Date"*). Such date shall be not more than 60 days after the date of such offer (if the Proposed Prepayment Date shall not be specified in such offer, the Proposed Prepayment Date shall be the first Business Day after the 45th day after the date of such offer).

(d)Acceptance/Rejection. A holder of Notes may accept the offer to prepay made pursuant to this **Section 8.3** by causing a notice of such acceptance to be delivered to the Company not later than 15 days after receipt by such holder of the most recent offer of prepayment. A failure by a holder of Notes to respond to an offer to prepay made pursuant to this **Section 8.3** shall be deemed to constitute a rejection of such offer by such holder.

(e)Prepayment. Prepayment of the Notes to be prepaid pursuant to this **Section 8.3** shall be at 100% of the principal amount of such Notes, together with interest on such Notes accrued to the date of prepayment, but without Make-Whole Amount or other premium. The prepayment shall be made on the Proposed Prepayment Date.

(f)Officer's Certificate. Each offer to prepay the Notes pursuant to this **Section 8.3** shall be accompanied by a certificate, executed by a Senior Financial Officer of the Company and dated the date of such offer, specifying: (i) the Proposed Prepayment Date; (ii) that such offer is made pursuant to this **Section 8.3**; (iii) the principal amount of each Note offered to be prepaid; (iv) the interest that would be due on each Note offered to be prepaid, accrued to the Proposed Prepayment Date; (v) that the conditions of this **Section 8.3** have been fulfilled; and (vi) in reasonable detail, the nature and date of the Change in Control.

(g)Certain Definitions. *"Change in Control"* shall be deemed to have occurred if any person (as such term is used in Section 13(d) and Section 14(d)(2) of the Exchange Act as in effect on the date of the Closing) or related persons constituting a group (as such term is used in Rule 13d-5 under the Exchange Act), other than AEP or any of its wholly-owned direct or indirect subsidiaries,

(i) become the "beneficial owners" (as such term is used in Rule 13d-3 under the Exchange Act as in effect on the date of the Closing), directly or indirectly, of more than 50% of the total voting power of all classes then outstanding of the Company's Voting Stock, or

(ii) acquire after the date of the Closing (x) the power to elect, appoint or cause the election or appointment of at least a majority of the members of the board of directors of the Company, through beneficial ownership of the capital stock of the Company or otherwise, or (y) all or substantially all of the properties and assets of the Company.

A *"Change in Control Prepayment Event"* occurs if, within the period of 120 days from and including the date on which a Change in Control occurs, either

(i) there are Rated Securities outstanding at the time of such Change in Control and a Rating Downgrade in respect of such Change in Control occurs, or

(ii) at such time there are no Rated Securities and the Company fails to obtain (whether by failing to seek a rating or otherwise) either

(A) a Corporate Credit Rating, or

(B) a rating of any other unsecured and unsubordinated Indebtedness which has a remaining maturity of five years or more (and which does not have the benefit of a guarantee from any Person other than any such Person that at such time also so guarantees the obligations of the Company under this Agreement and the Notes) of either (1) the Company or (2) the Person which has acquired the Company as a result of such Change in Control, so long as such Person has become an obligor under or guarantor of the Notes pursuant to documentation reasonably satisfactory to the Required Holders,

from a Rating Agency, of at least Investment Grade (a *"Negative Rating Event"*), in each case after giving pro forma effect to the transaction giving rise to such Change in Control.

For the avoidance of doubt, a Change in Control and the related Rating Downgrade or, as the case may be, Negative Rating Event, together (but not individually) constitute the Change in Control Prepayment Event).

"*Control Event*" means:

(i) the execution by the Company or any of its Subsidiaries or Affiliates of any agreement or letter of intent with respect to any proposed transaction or event or series of transactions or events which, individually or in the aggregate, may reasonably be expected to result in a Change in Control,

(ii) the execution of any written agreement which, when fully performed by the parties thereto, would result in a Change in Control, or

(iii) the making of any written offer by any person (as such term is used in Section 13(d) and Section 14(d)(2) of the Exchange Act as in effect on the date of the Closing) or related persons constituting a group (as such term is used in Rule 13d-5 under the Exchange Act as in effect on the date of the Closing) to the holders of the common stock of the Company, which offer, if accepted by the requisite number of holders, would result in a Change in Control.

"Corporate Credit Rating" means a rating of the Company or of the Person which acquires control of the Company as a result of a Change in Control if such Person has become an obligor under or guarantor of the Notes pursuant to documentation reasonably satisfactory to the Required Holders, of at least Investment Grade.

"Investment Grade" means a rating of BBB-/Baa3 (as applicable), or their respective equivalents for the time being, or better; *provided*, if such rating is "BBB-" in the case of S&P or "Baa3" in the case of Moody's, then such Person or Indebtedness shall not have been placed on "credit watch" and shall not have a "negative outlook" from S&P and Moody's.

"Rated Securities" means the Notes, if at any time and for so long as they shall have a rating from a Rating Agency, and otherwise any other unsecured and unsubordinated Indebtedness of the Company having a remaining maturity of five years or more (and which does not have the benefit of a guarantee from any Person other than any such Person that at such time also so guarantees the obligations of the Company under this Agreement and the Notes) which is rated by a Rating Agency.

"Rating Agency" means Standard & Poor's Ratings Services (*"S&P"*) or Moody's Investors Service, Inc. (*"Moody's"*) or any of their respective subsidiaries and their successors; provided, that if either of Moody's or S&P ceases to provide rating services to issuers or investors, the Company may appoint a replacement for such Rating Agency that is reasonably acceptable to Bankers Trust Company and its successors and assigns, the trustee under the Indenture, dated as of September 1, 1997, by and between the Company and Bankers Trust Company.

"Rating Downgrade" shall be deemed to have occurred in respect of a Change in Control if, within 120 days from and including the date on which the Change in Control occurs, the rating assigned to the Rated Securities by any Rating Agency (whether provided at the invitation of the Company or of its own volition) which is current immediately before the time the Change in Control occurs (i) if Investment Grade, is either lowered by such Rating Agency such that it is no longer Investment Grade or withdrawn and not replaced by an Investment Grade rating of another Rating Agency or (ii) if below Investment Grade, is not raised by such Rating Agency to Investment Grade.

All calculations contemplated in this **Section 8.3** involving the capital stock of any Person shall be made with the assumption that all convertible Securities of such Person then outstanding and all convertible Securities issuable upon the exercise of any warrants, options and other rights outstanding at such time were converted at such time and that all options, warrants and similar rights to acquire shares of capital stock of such Person were exercised at such time.

Section 8.4. Allocation of Partial Prepayments. In the case of each partial prepayment of the Notes pursuant to **Section 8.2**, the principal amount of the Notes of any series to be prepaid shall be allocated pro rata among all of the Notes of such series of the Notes being prepaid at such time in proportion, as nearly as practicable, to the respective unpaid principal amounts thereof not theretofore called for prepayment. All partial prepayments made pursuant to **Section 8.3** shall be applied only to the Notes of the holders who have elected to participate in such prepayment.

Section 8.5. Maturity; Surrender, Etc. In the case of each prepayment of Notes pursuant to this **Section 8**, the principal amount of each Note to be prepaid shall mature and become due and payable on the date fixed for such prepayment (which shall be a Business Day), together with interest on such principal amount accrued to such date and the applicable Make-Whole Amount, if any. From and after such date, unless the Company shall fail to pay such principal amount when so due and payable, together with the interest and Make-Whole Amount, if any, as aforesaid, interest on such principal amount shall cease to accrue. Any Note paid or prepaid in full shall be surrendered to the Company and cancelled and shall not be reissued, and no Note shall be issued in lieu of any prepaid principal amount of any Note.

Section 8.6. Purchase of Notes. The Company will not and will not permit any Affiliate to purchase, redeem, prepay or otherwise acquire, directly or indirectly, any of the outstanding Notes except (a) upon the payment or prepayment of the Notes in accordance with the terms of this Agreement and the Notes or (b) pursuant to an offer to purchase made by the Company or an Affiliate pro rata to the holders of all Notes at the time outstanding upon the same terms and conditions. Any such offer shall provide each holder with sufficient information to enable it to make an informed decision with respect to such offer, and shall remain open for at least 10 Business Days. If the holders of more than 25% of the principal amount of the Notes then outstanding accept such offer, the Company shall promptly notify the remaining holders of such fact and the expiration date for the acceptance by holders of Notes of such offer shall be extended by the number of days necessary to give each such remaining holder at least 5 Business Days from its receipt of such notice to accept such offer. The Company will promptly cancel all Notes acquired by it or any Affiliate pursuant to any payment, prepayment or purchase of Notes pursuant to any provision of this Agreement and no Notes may be issued in substitution or exchange for any such Notes.

Section 8.7. Make-Whole Amount. The term *"Make-Whole Amount"* means, with respect to any Note, an amount equal to the excess, if any, of the Discounted Value of the Remaining Scheduled Payments with respect to the Called Principal of such Note over the amount of such Called Principal; *provided* that the Make-Whole Amount may in no event be less than zero. For the purposes of determining the Make-Whole Amount, the following terms have the following meanings:

"Called Principal" means, with respect to any Note, the principal of such Note that is to be prepaid pursuant to **Section 8.2** or has become or is declared to be immediately due and payable pursuant to **Section 12.1**, as the context requires.

"Discounted Value" means, with respect to the Called Principal of any Note, the amount obtained by discounting all Remaining Scheduled Payments with respect to such Called Principal from their respective scheduled due dates to the Settlement Date with respect to such Called Principal, in accordance with accepted financial practice and at a discount factor (applied on the same periodic basis as that on which interest on such Note is payable) equal to the Reinvestment Yield with respect to such Called Principal.

"Reinvestment Yield" means, with respect to the Called Principal of any Note, 0.50% (50 basis points) over the yield to maturity implied by (i) the yields reported as of 10:00 a.m. (New York City time) on the second Business Day preceding the Settlement Date with respect to such Called Principal, on the display designated as "Page PX1" (or such other display as may replace Page PX1) on Bloomberg Financial Markets for the most recently issued actively traded on the run U.S. Treasury securities having a maturity equal to the Remaining Average Life of such Called Principal as of such Settlement Date, or (ii) if such yields are not reported as of such time or the yields reported as of such time are not ascertainable (including by way of interpolation), the Treasury Constant Maturity Series Yields reported, for the latest day for which such yields have been so reported as of the second Business Day preceding the Settlement Date with respect to such Called Principal, in Federal Reserve Statistical Release H.15 (or any comparable successor publication) for actively traded U.S. Treasury securities having a constant maturity equal to the Remaining Average Life of such Called Principal as of such Settlement Date. In the case of each determination under clause (i) or clause (ii), as the case may be, of the preceding sentence, such implied yield will be determined, if necessary, by (a) converting U.S. Treasury bill quotations to bond-equivalent yields in accordance with accepted financial practice and (b) interpolating linearly between (1) the most recently issued actively traded, on the run U.S. Treasury security with the maturity closest to and greater than such Remaining Average Life and (2) the most recently issued actively traded on the run U.S. Treasury security with the maturity closest to and less than such Remaining Average Life. The Reinvestment Yield shall be rounded to the number of decimal places as appears in the interest rate of the applicable Note.

"Remaining Average Life" means, with respect to any Called Principal, the number of years (calculated to the nearest one-twelfth year) obtained by dividing (a) such Called Principal into (b) the sum of the products obtained by multiplying (i) the principal component of each Remaining Scheduled Payment with respect to such Called Principal by (ii) the number of years (calculated to the nearest one-twelfth year) that will elapse between the Settlement Date with respect to such Called Principal and the scheduled due date of such Remaining Scheduled Payment.

"Remaining Scheduled Payments" means, with respect to the Called Principal of any Note, all payments of such Called Principal and interest thereon that would be due after the Settlement Date with respect to such Called Principal if no payment of such Called Principal were made prior to its scheduled due date; *provided* that if such

Settlement Date is not a date on which interest payments are due to be made under the terms of such Note, then the amount of the next succeeding scheduled interest payment will be reduced by the amount of interest accrued to such Settlement Date and required to be paid on such Settlement Date pursuant to **Section 8.2** or **12.1**.

"Settlement Date" means, with respect to the Called Principal of any Note, the date on which such Called Principal is to be prepaid pursuant to **Section 8.2** or has become or is declared to be immediately due and payable pursuant to **Section 12.1**, as the context requires.

Section 9. *AFFIRMATIVE COVENANTS.*

From the date of this Agreement until the Second Closing and thereafter, so long as any of the Notes are outstanding, the Company covenants that:

Section 9.1. Compliance with Laws. Without limiting **Section 10.6**, the Company will, and will cause each of its Subsidiaries to, comply with all laws, ordinances or governmental rules or regulations to which each of them is subject, including, without limitation, ERISA, Environmental Laws, the USA Patriot Act and the other laws and regulations that are referred to in **Section 5.16**, and will obtain and maintain in effect all licenses, certificates, permits, franchises and other governmental authorizations necessary to the ownership of their respective properties or to the conduct of their respective businesses, in each case to the extent necessary to ensure that non-compliance with such laws, ordinances or governmental rules or regulations or failures to obtain or maintain in effect such licenses, certificates, permits, franchises and other governmental authorizations would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

Section 9.2. Insurance. The Company will, and will cause each of its Subsidiaries to, maintain, with financially sound and reputable insurers, insurance with respect to their respective properties and businesses against such casualties and contingencies, of such types, on such terms and in such amounts (including deductibles, co-insurance and self-insurance, if adequate reserves are maintained with respect thereto) as is customary in the case of entities of established reputations engaged in the same or a similar business, owning similar properties and located in the same general area as the Company and its Subsidiaries, except where any failure to maintain such insurance would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect; *provided, however,* that so long as no Event of Default hereunder shall have occurred and be continuing, the Company may self-insure by way of deductibles, through its captive insurance company, or otherwise, such amount as is customarily maintained on similar properties by companies of similar size and financial standing and having similar operations and to the extent consistent with prudent business practices.

Section 9.3. Maintenance of Properties. The Company will, and will cause each of its Subsidiaries to, maintain and keep, or cause to be maintained and kept, their respective properties in good repair, working order and condition (other than ordinary wear and tear), so that the business carried on in connection therewith may be properly conducted at all times; *provided* that this **Section 9.3** shall not prevent the Company or any Subsidiary from discontinuing the operation and the maintenance of any of its properties if such discontinuance is desirable in the conduct of its business and the Company has concluded that such discontinuance would not, individually or in the aggregate, reasonably be expected to have a Material Adverse Effect.

Section 9.4. Payment of Taxes and Claims. The Company will, and will cause each of its Subsidiaries to, file all tax returns required to be filed in any jurisdiction and to pay and discharge all taxes shown to be due and payable on such returns and all other taxes, assessments, governmental charges, or levies imposed on them or any of their properties, assets, income or franchises, to the extent the same have become due and payable and before they have become delinquent and all claims for which sums have become due and payable that have or might become a Lien on properties or assets of the Company or any Subsidiary; *provided* that neither the Company nor any Subsidiary need pay any such tax, assessment, charge, levy or claim if (a) the amount, applicability or validity thereof is contested by the Company or such Subsidiary on a timely basis in good faith and in appropriate proceedings, and the Company has established adequate reserves therefor in accordance with GAAP on the books of the Company or such Subsidiary or (b) the nonpayment of all such taxes, assessments, charges, levies and claims in the aggregate would not reasonably be expected to have a Material Adverse Effect.

Section 9.5. Legal Existence, Etc. Subject to **Section 10.3**, the Company will at all times preserve and keep in full force and effect its legal existence and the Company will at all times preserve and keep in full force and effect the legal existence of each of its Subsidiaries (unless merged into the Company or a Wholly-owned Subsidiary) and all rights and franchises of the Company and its Subsidiaries unless, in the good faith judgment of the Company, the termination of or failure to preserve and keep in full force and effect such legal existence, right or franchise would not, individually or in the aggregate, have a Material Adverse Effect.

Section 9.6. Notes to Rank Pari Passu. The Notes and all other obligations under this Agreement of the Company are and at all times shall rank at least *pari passu* in right of payment with all other present and future unsecured Indebtedness (actual or contingent) of the Company which is not expressed to be subordinate or junior in rank to any other unsecured Indebtedness of the Company.

Section 9.7. Books and Records. The Company will, and will cause each of its Subsidiaries to, maintain proper books of record and account in conformity with GAAP and all applicable requirements of any Governmental Authority having legal or regulatory jurisdiction over the Company, or such Subsidiary, as the case may be. The Company will keep books, records and accounts which, in reasonable detail, accurately reflect all transactions and dispositions of assets. The Company has devised a system of internal accounting controls sufficient to provide reasonable assurances that its books, records and accounts accurately reflect all transactions and dispositions of assets and the Company will, and will cause each of its Subsidiaries to, continue to maintain such system.

Section 10. Negative Covenants.

From the date of this Agreement until the Second Closing and thereafter, so long as any of the Notes are outstanding, the Company covenants that:

Section 10.1. Leverage Ratio. The Company will maintain a ratio of Consolidated Indebtedness to Consolidated Capital as of the last day of each March, June, September and December of not greater than 0.70 to 1.00.

Section 10.2. Limitation on Secured Debt. The Company shall not create or suffer to be created or to exist or permit any of its Subsidiaries to create or suffer to be created or to exist any additional mortgage, pledge, security interest, or other lien (collectively *"Liens"*) on any utility properties or tangible assets now owned or hereafter acquired by the Company or its Subsidiaries to secure any Indebtedness for borrowed money (*"Secured Debt"*), without providing that the Notes will be similarly secured. This restriction does not prevent the creation or existence of:

(a) Liens on property existing at the time of acquisition or construction of such property (or created within one year after completion of such acquisition or construction), whether by purchase, merger, construction or otherwise, or to secure the payment of all or any part of the purchase price or construction cost thereof, including the extension of any Liens to repairs, renewals, replacements, substitutions, betterments, additions, extensions and improvements then or thereafter made on the property subject thereto;

(b) financing of the Company's accounts receivable for electric service;

(c) any extensions, renewals or replacements (or successive extensions, renewals or replacements), in whole or in part, of Liens permitted by the foregoing clauses; and

(d) the pledge of any bonds or other Securities at any time issued under any of the Secured Debt permitted by the above clauses.

In addition to the permitted issuances above, Secured Debt not otherwise so permitted may be issued in an amount that does not exceed 15% of Net Tangible Assets as defined below; *provided* that, notwithstanding the foregoing, in the event that at any time the Company provides a Lien to or for the benefit of the lenders under a Credit Facility or an agent on their behalf, then the Company will grant to and for the benefit of the holders of the Notes a similar first priority Lien (subject only to Liens otherwise permitted by this **Section 10.2**, and ranking *pari passu* with the Lien provided to or for the benefit of the lenders and/or the agent, as the case may be, under such Credit Facility), over the same assets, property and undertaking of the Company as those encumbered in respect of such Credit Facility, in form and substance satisfactory to the Required Holders with such security to be the subject of an intercreditor agreement among the lenders and/or the agent, as the case may be, under such Credit Facility or the agent on their behalf, as the case may be, and the holders of Notes, which shall be satisfactory in form and substance to the Required Holders.

"Net Tangible Assets" means the total of all assets (including revaluations thereof as a result of commercial appraisals, price level restatement or otherwise) appearing on the Company's balance sheet, net of applicable reserves and deductions, but excluding goodwill, trade names, trademarks, patents, unamortized debt discount, energy trading contracts, regulatory assets, deferred charges and all other like intangible assets (which term shall not be construed to

include such revaluations), less the aggregate of the Company's current liabilities appearing on such balance sheet.

This restriction also will not apply to or prevent the creation or existence of leases (operating or capital) made, or existing on property acquired, in the ordinary course of business.

Section 10.3. Mergers, Consolidations, Etc. The Company will not, and will not permit any Subsidiary to, consolidate with or be a party to a merger with any other Person, or sell, lease or otherwise dispose of all or substantially all of its assets; *provided* that:

(a) any Subsidiary may merge or consolidate with or into the Company or any Wholly-owned Subsidiary so long as in (i) any merger or consolidation involving the Company, the Company shall be the surviving or continuing corporation and (ii) in any merger or consolidation involving a Wholly-owned Subsidiary (and not the Company), the Wholly-owned Subsidiary shall be the surviving or continuing corporation or limited liability company;

(b) the Company may consolidate or merge with or into any other corporation or limited liability company if (i) the corporation or limited liability company which results from such consolidation or merger (the *"Surviving Person"*) is organized under the laws of any state of the United States or the District of Columbia, (ii) the due and punctual payment of the principal of and premium, if any, and interest on all of the Notes, according to their tenor, and the due and punctual performance and observation of all of the covenants in the Notes and this Agreement to be performed or observed by the Company are expressly assumed in writing by the Surviving Person pursuant to an agreement satisfactory to the Required Holders and the Surviving Person shall furnish to the holders of the Notes an opinion of counsel satisfactory to the Required Holders to the effect that the instrument of assumption has been duly authorized, executed and delivered and constitutes the legal, valid and binding contract and agreement of the Surviving Person enforceable in accordance with its terms, except as enforcement of such terms may be limited by bankruptcy, insolvency, reorganization, moratorium and similar laws affecting the enforcement of creditors' rights generally and by general equitable principles, and (iii) at the time of such consolidation or merger and immediately after giving effect thereto, no Default or Event of Default would exist;

(c) the Company may sell or otherwise dispose of all or substantially all of its assets to any Person for consideration which represents the fair market value of such assets (as determined in good faith by the Board of Directors of the Company) at the time of such sale or other disposition if (i) the acquiring Person (the *"Acquiring Person"*) is a corporation or limited liability company organized under the laws of any state of the United States or the District of Columbia, (ii) the due and punctual payment of the principal of and premium, if any, and interest on all the Notes, according to their tenor, and the due and punctual performance and observance of all of the covenants in the Notes and in this Agreement to be performed or observed by the Company are expressly assumed in writing by the Acquiring Person pursuant to an agreement satisfactory to the Required Holders and the Acquiring Person shall furnish to the holders of the Notes an opinion of counsel satisfactory to the Required Holders to the effect that the instrument of assumption has been duly authorized, executed and delivered and constitutes the legal, valid and binding contract and agreement of such Acquiring Person enforceable in accordance with its terms, except as enforcement of such terms may be limited by bankruptcy, insolvency, reorganization, moratorium and similar laws affecting the enforcement of creditors' rights generally and by general equitable principles, and (iii) at the time of such sale or disposition and immediately after giving effect thereto, no Default or Event of Default would exist.

Section 10.4. Transactions with Affiliates. The Company will not and will not permit any Subsidiary to enter into directly or indirectly any transaction or group of related transactions (including without limitation the purchase, lease, sale or exchange of properties of any kind or the rendering of any service) with any Affiliate (other than the Company or another Subsidiary), except in the ordinary course and pursuant to the reasonable requirements of the Company's or such Subsidiary's business.

Section 10.5. Line of Business. The Company will not and will not permit any Subsidiary to engage in any business if, as a result, the general nature of the business in which the Company and its Subsidiaries, taken as a whole, would then be engaged would be substantially changed from the general nature of the business in which the Company is engaged on the date of this Agreement as described in the Memorandum.

Section 10.6. Terrorism Sanctions Regulations. The Company will not and will not permit any Controlled Entity (a) to become (including by virtue of being owned or controlled by a Blocked Person), own or control a Blocked Person or any Person that is the target of sanctions imposed by the United Nations or by the European Union, or (b) directly or indirectly to have any investment in or engage in any dealing or transaction (including, without limitation, any investment, dealing or transaction involving the proceeds of the Notes) with any Person if such investment, dealing or transaction (i) would cause any Purchaser or holder to be in violation of any law or regulation applicable to such holder, or (ii) is prohibited by or subject to sanctions under any U.S. Economic Sanctions, or (c) to engage, nor shall any Affiliate of either engage, in any activity that could subject such Person or any Purchaser or holder to sanctions under CISADA or any similar law or regulation with respect to Iran or any other country that is subject to U.S. Economic Sanctions.

Section 11. EVENTS OF DEFAULT.

An *"Event of Default"* shall exist if any of the following conditions or events shall occur and be continuing:

(a) the Company defaults in the payment of any principal or Make-Whole Amount, if any, on any Note when the same becomes due and payable, whether at maturity or at a date fixed for prepayment or by declaration or otherwise; or

(b) the Company defaults in the payment of any interest on any Note for more than five Business Days after the same becomes due and payable; or

(c) the Company defaults in the performance of or compliance with any term contained in **Section 7.1(d)** or **Sections 10.1** through **10.3**; or

(d) the Company defaults in the performance of or compliance with any term contained herein (other than those referred to in **Sections 11(a)**, **(b)** and **(c)**) and such default is not remedied within 30 days after the earlier of (i) a Responsible Officer obtaining actual knowledge of such default and (ii) the Company receiving written notice of such default from any holder of a Note (any such written notice to be identified as a "notice of default" and to refer specifically to this **Section 11(d)**); or

(e) any representation or warranty made in writing by or on behalf of the Company or by any officer of the Company in this Agreement or in any writing furnished in connection with the transactions contemplated hereby proves to have been false or incorrect in any material respect on the date as of which made; or

(f) any event shall occur or condition shall exist under any agreement or instrument relating to Indebtedness of the Company or any Subsidiary (but excluding Indebtedness outstanding hereunder) outstanding in a principal or notional amount of at least $50,000,000 in the aggregate if the effect of such event or condition is to accelerate or require early termination of the maturity or tenor of such Indebtedness, or any such Indebtedness shall be declared to be due and payable, or required to be prepaid or redeemed (other than by a regularly scheduled required prepayment or redemption), terminated, purchased or defeased, or an offer to prepay, redeem, purchase or defease such Indebtedness shall be required to be made, in each case prior to the stated maturity or the original tenor thereof; or

(g) the Company or any Significant Subsidiary (i) is generally not paying, or admits in writing its inability to pay, its debts as they become due, (ii) files, or consents by answer or otherwise to the filing against it of, a petition for relief or reorganization or arrangement or any other petition in bankruptcy, for liquidation or to take advantage of any bankruptcy, insolvency, reorganization, moratorium or other similar law of any jurisdiction, (iii) makes an assignment for the benefit of its creditors, (iv) consents to the appointment of a custodian, receiver, trustee or other officer with similar powers with respect to it or with respect to any substantial part of its property, (v) is adjudicated as insolvent or to be liquidated, or (vi) takes corporate action for the purpose of any of the foregoing; or

(h) a court or Governmental Authority of competent jurisdiction enters an order appointing, without consent by the Company or any of its Significant Subsidiaries, a custodian, receiver, trustee or other officer with similar powers with respect to it or with respect to any substantial part of its property, or constituting an order for relief or approving a petition for relief or reorganization or any other petition in bankruptcy or for liquidation or to take advantage of any bankruptcy or insolvency law of any jurisdiction, or ordering the dissolution, winding-up or liquidation of the Company or any of its Significant Subsidiaries, or any such petition shall be filed against the Company or any of its Significant Subsidiaries and such petition shall not be dismissed within 60 days; or

(i) any judgment or order for the payment of money in excess of $50,000,000 to the extent not paid or insured shall be rendered against the Company or any Subsidiary and either (i) enforcement proceedings shall have been commenced by any creditor upon such judgment or order or (ii) there shall be any period of 30 consecutive days during which a stay of enforcement of such judgment or order, by reason of a pending appeal or otherwise, shall not be in effect; or

(j) if (i) any Plan which is a pension plan within the meaning of section 3(2) of ERISA shall fail to satisfy the minimum funding standards of ERISA or the Code for any plan year or part thereof or a waiver of such standards or extension of any amortization period is sought or granted under section 412 of the Code, (ii) a notice of intent to terminate any Plan shall have been or is reasonably expected to be filed with the PBGC or the PBGC shall have instituted proceedings under ERISA section 4042 to terminate or appoint a trustee to administer any Plan or the PBGC shall have notified the Company or any ERISA Affiliate that a Plan may become a subject of any such proceedings, (iii) the aggregate "amount of unfunded benefit liabilities" (within the meaning of section 4001(a)(18) of ERISA) under all Plans, determined in accordance with Title IV of ERISA, shall exceed an amount that would reasonably be expected to have a Material Adverse Effect, (iv) the Company or any ERISA Affiliate shall have incurred or is reasonably expected to incur any liability with respect to any Plan pursuant to Title I or IV of ERISA or the penalty or excise tax provisions of the Code relating to employee benefit plans, (v) the Company or any ERISA Affiliate withdraws from any Multiemployer Plan, or (vi) the Company or any Subsidiary establishes or amends any employee welfare benefit plan that provides post-employment welfare benefits in a manner that would increase the liability of the Company or any Subsidiary thereunder; and any such event or events described in clauses (i) through (vi) above, either individually or together with any other such event or events, could reasonably be expected to have a Material Adverse Effect.

As used in **Section 11(j)**, the terms "employee benefit plan" and "employee welfare benefit plan" shall have the respective meanings assigned to such terms in section 3 of ERISA.

Section 12. REMEDIES ON DEFAULT, ETC.

Section 12.1. Acceleration. (a) If an Event of Default with respect to the Company described in **Section 11(g)** or **(h)** (other than an Event of Default described in clause (i) of **Section 11(g)** or described in clause (vi) of **Section 11(g)** by virtue of the fact that such clause encompasses clause (i) of **Section 11(g)**) has occurred, all the Notes then outstanding shall automatically become immediately due and payable.

(b) If any other Event of Default has occurred and is continuing, any holder or holders of more than 50% in principal amount of the Notes at the time outstanding may at any time at its or their option, by notice or notices to the Company, declare all the Notes then outstanding to be immediately due and payable.

(c) If any Event of Default described in **Section 11(a)** or **(b)** has occurred and is continuing, any holder or holders of Notes at the time outstanding affected by such Event of Default may at any time, at its or their option, by notice or notices to the Company, declare all the Notes held by it or them to be immediately due and payable.

Upon any Notes becoming due and payable under this **Section 12.1**, whether automatically or by declaration, such Notes will forthwith mature and the entire unpaid principal amount of such Notes, plus (i) all accrued and unpaid interest thereon (including, but not limited to, interest accrued thereon at the applicable Default Rate) and (ii) the Make-Whole Amount determined in respect of such principal amount (to the full extent permitted by applicable law), shall all be immediately due and payable, in each and every case without presentment, demand, protest or further notice, all of which are hereby waived. The Company acknowledges, and the parties hereto agree, that each holder of a Note has the right to maintain its investment in the Notes free from repayment by the Company (except as herein specifically provided for), and that the provision for payment of a Make-Whole Amount by the Company in the event that the Notes are prepaid or are accelerated as a result of an Event of Default, is intended to provide compensation for the deprivation of such right under such circumstances.

Section 12.2. Other Remedies. If any Default or Event of Default has occurred and is continuing, and irrespective of whether any Notes have become or have been declared immediately due and payable under **Section 12.1**, the holder of any Note at the time outstanding may proceed to protect and enforce the rights of such holder by an action at law, suit in equity or other appropriate proceeding, whether for the specific performance of any agreement contained herein or in any Note, or for an injunction against a violation of any of the terms hereof or thereof, or in aid of the exercise of any power granted hereby or thereby or by law or otherwise.

Section 12.3. Rescission. At any time after any Notes have been declared due and payable pursuant to **Section 12.1(b)** or **(c)**, the holders of not less than 51% in principal amount of the Notes then outstanding, by written notice to the Company, may rescind and annul any such declaration and its consequences if (a) the Company has paid all overdue interest on the Notes, all principal of and Make-Whole Amount, if any, on any Notes that are due and payable and are unpaid other than by reason of such declaration, and all interest on such overdue principal and Make-Whole Amount, if any, and (to the extent permitted by applicable law) any overdue interest in respect of the Notes, at the applicable Default Rate, (b) neither the Company nor any other Person shall have paid any amounts which have become due solely by reason of such declaration, (c) all Events of Default and Defaults, other than non-payment of amounts that have become due solely by reason of such declaration, have been cured or have been waived pursuant to **Section 17**, and (d) no judgment or decree has been entered for the payment of any monies due pursuant hereto or to the Notes. No rescission and annulment under this **Section 12.3** will extend to or affect any subsequent Event of Default or Default or impair any right consequent thereon.

Section 12.4. No Waivers or Election of Remedies, Expenses, Etc. No course of dealing and no delay on the part of any holder of any Note in exercising any right, power or remedy shall operate as a waiver thereof or otherwise prejudice such holder's rights, powers or remedies. No right, power or remedy conferred by this Agreement or by any Note upon any holder thereof shall be exclusive of any other right, power or remedy referred to herein or therein or now or hereafter available at law, in equity, by statute or otherwise. Without limiting the obligations of the Company under **Section 15**, the Company will pay to the holder of each Note on demand such further amount as shall be sufficient to cover all costs and expenses of such holder incurred in any enforcement or collection under this **Section 12**, including, without limitation, reasonable attorneys' fees, expenses and disbursements of one special counsel for all holders of the Notes.

Section 13. Registration; Exchange; Substitution of Notes.

Section 13.1. Registration of Notes. The Company shall keep at its principal executive office a register for the registration and registration of transfers of Notes. The name and address of each holder of one or more Notes, each transfer thereof and the name and address of each transferee of one or more Notes shall be registered in such register. If any holder of one or more Notes is a nominee, then (a) the name and address of the beneficial owner of such Note or Notes shall also be registered in such register as an owner and holder thereof and (b) at any such beneficial owner's option, either such beneficial owner or its nominee may execute any amendment, waiver or consent pursuant to this Agreement. Prior to due presentment for registration of transfer, the Person(s) in whose name any Note(s) shall be registered shall be deemed and treated as the owner and holder thereof for all purposes hereof, and the Company shall not be affected by any notice or knowledge to the contrary. The Company shall give to any holder of a Note that is an Institutional Investor promptly upon request therefor, a complete and correct copy of the names and addresses of all registered holders of Notes.

Section 13.2. Transfer and Exchange of Notes. Upon surrender of any Note to the Company at the address and to the attention of the designated officer (all as specified in **Section 18(iii)**) for registration of transfer or exchange (and in the case of a surrender for registration of transfer accompanied by a written instrument of transfer duly executed by the registered holder of such Note or such holder's attorney duly authorized in writing and accompanied by the relevant name, address and other information for notices of each transferee of such Note or part thereof), within ten Business Days thereafter, the Company shall execute and deliver, at the Company's expense (except as provided below), one or more new Notes (as requested by the holder thereof) in exchange therefor, of the same series and in an aggregate principal amount equal to the unpaid principal amount of the surrendered Note. Each such new Note shall be payable to such Person as such holder may request and shall be substantially in the form of **Exhibit 1-A** or **Exhibit 1-B**, as applicable. Each such new Note shall be dated and bear interest from the date to which interest shall have been paid on the surrendered Note or dated the date of the surrendered Note if no interest shall have been paid thereon. The Company may require payment of a sum sufficient to cover any stamp tax or governmental charge imposed in respect of any such transfer of Notes. Notes shall not be transferred in denominations of less than $100,000; *provided* that if necessary to enable the registration of transfer by a holder of its entire holding of Notes of a series, one Note of such series may be in a denomination of less than $100,000. Any transferee, by its acceptance of a Note registered in its name (or the name of its nominee), shall be deemed to have made the representation set forth in **Section 6.2**.

Section 13.3. Replacement of Notes. Upon receipt by the Company at the address and to the attention of the designated officer (all as specified in **Section 18(iii)**) of evidence reasonably satisfactory to it of the ownership of and the loss, theft, destruction or mutilation of any Note (which evidence shall be, in the case of an Institutional Investor, notice from such Institutional Investor of such ownership and such loss, theft, destruction or mutilation), and

(a) in the case of loss, theft or destruction, of indemnity reasonably satisfactory to it (*provided* that if the holder of such Note is, or is a nominee for, an original Purchaser or another holder of a Note with a minimum net worth of at least

$50,000,000 or a Qualified Institutional Buyer, such Person's own unsecured agreement of indemnity shall be deemed to be satisfactory), or

(b) in the case of mutilation, upon surrender and cancellation thereof,

within ten Business Days thereafter, the Company at its own expense shall execute and deliver, in lieu thereof, a new Note of the same series, dated and bearing interest from the date to which interest shall have been paid on such lost, stolen, destroyed or mutilated Note or dated the date of such lost, stolen, destroyed or mutilated Note if no interest shall have been paid thereon.

Section 14. PAYMENTS ON NOTES.

Section 14.1. Place of Payment. Subject to **Section 14.2**, payments of principal, Make-Whole Amount, if any, and interest becoming due and payable on the Notes shall be made in New York, New York at the principal office of Citibank N.A. in such jurisdiction. The Company may at any time, by notice to each holder of a Note, change the place of payment of the Notes so long as such place of payment shall be either the principal office of the Company in such jurisdiction or the principal office of a bank or trust company in such jurisdiction.

Section 14.2. Home Office Payment. So long as any Purchaser or its nominee shall be the holder of any Note, and notwithstanding anything contained in **Section 14.1** or in such Note to the contrary, the Company will pay all sums becoming due on such Note for principal, Make-Whole Amount, if any, interest and all other amounts becoming due hereunder by the method and at the address specified for such purpose below such Purchaser's name in **Schedule A**, or by such other method or at such other address as such Purchaser shall have from time to time specified to the Company in writing for such purpose, without the presentation or surrender of such Note or the making of any notation thereon, except that upon written request of the Company made concurrently with or reasonably promptly after payment or prepayment in full of any Note, such Purchaser shall surrender such Note for cancellation, reasonably promptly after any such request, to the Company at its principal executive office or at the place of payment most recently designated by the Company pursuant to **Section 14.1**. The Company will make such payments in immediately available funds, no later than 11:00 a.m. New York time on the date due. If for any reason whatsoever the Company does not make any such payment by such 11:00 a.m. transmittal time, such payment shall be deemed to have been made on the next following Business Day and such payment shall bear interest at the Default Rate set forth in the Note. Prior to any sale or other disposition of any Note held by a Purchaser or its nominee, such Purchaser will, at its election, either endorse thereon the amount of principal paid thereon and the last date to which interest has been paid thereon or surrender such Note to the Company in exchange for a new Note or Notes of the same series pursuant to **Section 13.2**. The Company will afford the benefits of this **Section 14.2** to any Institutional Investor that is the direct or indirect transferee of any Note purchased by a Purchaser under this Agreement and that has made the same agreement relating to such Note as the Purchasers have made in this **Section 14.2**.

Section 15. EXPENSES, ETC.

Section 15.1. Transaction Expenses. Whether or not the transactions contemplated hereby are consummated, the Company will pay all costs and expenses (including reasonable attorneys' fees of a special counsel and, if reasonably required by the Required Holders, local or other counsel) incurred by the Purchasers and each other holder of a Note in connection with such transactions and in connection with any amendments, waivers or consents under or in respect of this Agreement or the Notes (whether or not such amendment, waiver or consent becomes effective), including, without limitation: (a) the costs and expenses incurred in enforcing or defending (or determining whether or how to enforce or defend) any rights under this Agreement or the Notes or in responding to any subpoena or other legal process or informal investigative demand issued in connection with this Agreement or the Notes, or by reason of being a holder of any Note, and (b) the costs and expenses, including financial advisors' fees, incurred in connection with the insolvency or bankruptcy of the Company or any Subsidiary or in connection with any work-out or restructuring of the transactions contemplated hereby and by the Notes. In the event that any such invoice is not paid within 30 Business Days after the Company's receipt thereof, interest on the amount of such invoice shall be due and payable at the Default Rate commencing with the 31st Business Day after the Company's receipt thereof until such invoice has been paid. The Company will pay, and will save each Purchaser and each other holder of a Note harmless from, (i) all claims in respect of any fees, costs or expenses, if any, of brokers and finders (other than those, if any, retained by a Purchaser or other holder in connection with its purchase of the Notes) and (ii) any and all wire transfer fees that any bank deducts from any payment under such Note to such holder or otherwise charges to a holder of a Note with respect to a payment under such Note.

Section 15.2. Survival. The obligations of the Company under this **Section 15** will survive the payment or transfer of any Note, the enforcement, amendment or waiver of any provision of this Agreement or the Notes, and the termination of this Agreement.

Section 16. Survival of Representations and Warranties; Entire Agreement.

All representations and warranties contained herein shall survive the execution and delivery of this Agreement and the Notes, the purchase or transfer by any Purchaser of any Note or portion thereof or interest therein and the payment of any Note, and may be relied upon by any subsequent holder of a Note, regardless of any investigation made at any time by or on behalf of such Purchaser or any other holder of a Note. All statements contained in any certificate or other instrument delivered by or on behalf of the Company pursuant to this Agreement shall be deemed representations and warranties of the Company under this Agreement. Subject to the preceding sentence, this Agreement and the Notes embody the entire agreement and understanding between each Purchaser and the Company and supersede all prior agreements and understandings relating to the subject matter hereof.

Section 17. Amendment and Waiver.

Section 17.1. Requirements. This Agreement and the Notes may be amended, and the observance of any term hereof or of the Notes may be waived (either retroactively or prospectively), only with the written consent of the Company and the Required Holders, except that:

(a) no amendment or waiver of any of **Sections 1, 2, 3, 4, 5, 6** or **21** hereof, or any defined term (as it is used therein), will be effective as to any Purchaser unless consented to by such Purchaser in writing; and

(b) no amendment or waiver may, without the written consent of each Purchaser and the holder of each Note at the time outstanding, (i) subject to **Section 12** relating to acceleration or rescission, change the amount or time of any prepayment or payment of principal of, or reduce the rate or change the time of payment or method of computation of (x) interest on the Notes or (y) the Make Whole Amount (ii) change the percentage of the principal amount of the Notes the holders of which are required to consent to any amendment or waiver or the principal amount of a Note that the Purchasers are to purchase pursuant to **Section 2** upon the satisfaction of the conditions to a Closing that appear in **Section 4**; or (iii) amend any of **Sections 8** (except as set forth in the second sentence of **Section 8.2** and **11(a), 11(b), 12, 17** or **20**.

Section 17.2. Solicitation of Holders of Notes.

(a) *Solicitation.* The Company will provide each Purchaser and holder of the Notes (irrespective of the amount or series of Notes then owned by it) with sufficient information, sufficiently far in advance of the date a decision is required, to enable such Purchaser and such holder to make an informed and considered decision with respect to any proposed amendment, waiver or consent in respect of any of the provisions hereof or of the Notes. The Company will deliver executed or true and correct copies of each amendment, waiver or consent effected pursuant to the provisions of this **Section 17** to each Purchaser and each holder of outstanding Notes promptly following the date on which it is executed and delivered by, or receives the consent or approval of, the requisite Purchasers or holders of Notes.

(b) *Payment.* The Company will not directly or indirectly pay or cause to be paid any remuneration, whether by way of supplemental or additional interest, fee or otherwise, or grant any security or provide other credit support, to any Purchaser or holder of any series of Notes as consideration for or as an inducement to the entering into by such Purchaser or holder of Notes of any waiver or amendment of any of the terms and provisions hereof or of any Note unless such remuneration is concurrently paid, or security is concurrently granted or other credit support concurrently provided, on the same terms, ratably to each Purchaser and holder of each series of Notes then outstanding even if such Purchaser or holder did not consent to such waiver or amendment.

(c) *Consent in Contemplation of Transfer.* Any consent made pursuant to this **Section 17.2** by the holder of any Note of any series that has transferred or has agreed to transfer such Note to the Company or any Affiliate of the Company and has provided or has agreed to provide such written consent as a condition to such transfer shall be void and of no force or effect except solely as to such holder, and any amendments effected or waivers granted or to be effected or granted that would not have been or would not be so effected or granted but for such consent (and the consents of all other holders of Notes that were acquired under the same or similar conditions) shall be void and of no force or effect except solely as to such transferring holder.

Section 17.3. Binding Effect, Etc. Any amendment or waiver consented to as provided in this **Section 17** applies equally to all Purchasers and holders of each series of Notes and is binding upon them and upon each future holder of any Note of any series and upon the Company without regard to whether such Note has been marked to indicate such amendment or waiver. No such amendment or waiver will extend to or affect any obligation, covenant, agreement, Default or Event of Default not expressly amended or waived or impair any right consequent thereon. No course of dealing between the Company and any Purchaser or holder of any Note of any series nor any delay in exercising any rights hereunder or under any Note of any series shall operate as a waiver of any rights of any Purchaser or holder of such Note.

Section 17.4. Notes Held by Company, Etc. Solely for the purpose of determining whether the holders of the requisite percentage of the aggregate principal amount of Notes then outstanding approved or consented to any amendment, waiver or consent to be given under this Agreement or the Notes, or have directed the taking of any action provided herein or in the Notes to be taken upon the direction of the holders of a specified percentage of the aggregate principal amount of Notes then outstanding, Notes directly or indirectly owned by the Company or any of its Affiliates shall be deemed not to be outstanding.

Section 18. Notices.

Except to the extent otherwise provided in Section 7.4, all notices and communications provided for hereunder shall be in writing and sent (a) by telefacsimile if the sender on the same day sends a confirming copy of such notice by a recognized overnight delivery service (charges prepaid), or (b) by registered or certified mail with return receipt requested (postage prepaid), or (c) by a recognized overnight delivery service (with charges prepaid). Any such notice must be sent:

(i) if to any Purchaser or its nominee, to such Purchaser or nominee at the address specified for such communications in **Schedule A**, or at such other address as such Purchaser or nominee shall have specified to the Company in writing,

(ii) if to any other holder of any Note, to such holder at such address as such other holder shall have specified to the Company in writing, or

(iii) if to the Company, to the Company at its address set forth at the beginning hereof to the attention of Treasurer, with a copy to the attention of the General Counsel at the same address as above and Facsimile No.: 614-716-1687, or at such other address as the Company shall have specified to the holder of each Note in writing.

Notices under this **Section 18** will be deemed given only when actually received.

Section 19. Reproduction of Documents.

This Agreement and all documents relating thereto, including, without limitation, (a) consents, waivers and modifications that may hereafter be executed, (b) documents received by any Purchaser at the Closing (except the Notes themselves), and (c) financial statements, certificates and other information previously or hereafter furnished to any Purchaser, may be reproduced by such Purchaser by any photographic, photostatic, electronic, digital or other similar process and such Purchaser may destroy any original document so reproduced. The Company agrees and stipulates that, to the extent permitted by applicable law, any such reproduction shall be admissible in evidence as the original itself in any judicial or administrative proceeding (whether or not the original is in existence and whether or not such reproduction was made by such Purchaser in the regular course of business) and any enlargement, facsimile or further reproduction of such reproduction shall likewise be admissible in evidence. This **Section 19** shall not prohibit the Company or any other holder of Notes from contesting any such reproduction to the same extent that it could contest the original, or from introducing evidence to demonstrate the inaccuracy of any such reproduction.

Section 20. CONFIDENTIAL INFORMATION.

For the purposes of this **Section 20**, *"Confidential Information"* means information delivered to any Purchaser by or on behalf of the Company or any Subsidiary in connection with the transactions contemplated by or otherwise pursuant to this Agreement that is proprietary in nature and that was clearly marked or labeled or otherwise adequately identified when received by such Purchaser as being confidential information of the Company or such Subsidiary; *provided* that such term does not include information that (a) was publicly known or otherwise known to such Purchaser prior to the time of such disclosure, (b) subsequently becomes publicly known through no act or omission by such Purchaser or any Person acting on such Purchaser's behalf, (c) otherwise becomes known to such Purchaser other than through disclosure by the Company or any Subsidiary or (d) constitutes financial statements delivered to such Purchaser under **Section 7.1** that are otherwise publicly available. Each Purchaser will maintain the confidentiality of such Confidential Information in accordance with procedures adopted by such Purchaser in good faith to protect confidential information of third parties delivered to such Purchaser; *provided* that such Purchaser may deliver or disclose Confidential Information to (i) its directors, trustees, officers, employees, agents, attorneys and affiliates (to the extent such disclosure reasonably relates to the administration of the investment represented by its Notes), (ii) its financial advisors and other professional advisors who agree to hold confidential the Confidential Information substantially in accordance with the terms of this **Section 20**, (iii) any other holder of any Note, (iv) any Institutional Investor to which it sells or offers to sell such Note or any part thereof or any participation therein (if such Person has agreed in writing prior to its receipt of such Confidential Information to be bound by the provisions of this **Section 20**), (v) any Person from which it offers to purchase any security of the Company (if such Person has agreed in writing prior to its receipt of such Confidential Information to be bound by the provisions of this **Section 20**), (vi) any federal, state or provincial regulatory authority having jurisdiction over such Purchaser, (vii) the NAIC or the SVO or, in each case, any similar organization, or any nationally recognized rating agency that requires access to information about such Purchaser's investment portfolio or (viii) any other Person to which such delivery or disclosure may be necessary or appropriate (w) to effect compliance with any law, rule, regulation or order applicable to such Purchaser, (x) in response to any subpoena or other legal process, (y) in connection with any litigation to which such Purchaser is a party or (z) if an Event of Default has occurred and is continuing, to the extent such Purchaser may reasonably determine such delivery and disclosure to be necessary or appropriate in the enforcement or for the protection of the rights and remedies under such Purchaser's Notes and this Agreement. Each holder of a Note, by its acceptance of a Note, will be deemed to have agreed to be bound by and to be entitled to the benefits of this **Section 20** as though it were a party to this Agreement.

On reasonable request by the Company in connection with the delivery to any holder of a Note of information required to be delivered to such holder under this Agreement or requested by such holder (other than a holder that is a party to this Agreement or its nominee), such holder will enter into an agreement with the Company embodying the provisions of this **Section 20**.

In the event that as a condition to receiving access to information relating to the Company or its Subsidiaries in connection with the transactions contemplated by or otherwise pursuant to this Agreement, any Purchaser or holder of a Note is required to agree to a confidentiality undertaking (whether through IntraLinks, another secure website, a secure virtual workspace or otherwise) which is different from this Section 20, this Section 20 shall not be amended thereby and, as between such Purchaser or such holder and the Company, this Section 20 shall supersede any such other confidentiality undertaking.

Section 21. SUBSTITUTION OF PURCHASER.

Each Purchaser shall have the right to substitute any one of its Affiliates as the purchaser of the Notes that it has agreed to purchase hereunder, by written notice to the Company, which notice shall be signed by both such Purchaser and such Affiliate, shall contain such Affiliate's agreement to be bound by this Agreement and shall contain a confirmation by such Affiliate of the accuracy with respect to it of the representations set forth in **Section 6**. Upon receipt of such notice, any reference to such Purchaser in this Agreement (other than in this **Section 21**) shall be deemed to refer to such Affiliate in lieu of such original Purchaser. In the event that such Affiliate is so substituted as a Purchaser hereunder and such Affiliate thereafter transfers to such original Purchaser all of the Notes then held by such Affiliate, upon receipt by the Company of notice of such transfer, any reference to such Affiliate as a "Purchaser" in this Agreement (other than in this **Section 21**) shall no longer be deemed to refer to such Affiliate, but shall refer to such original Purchaser, and such original Purchaser shall again have all the rights of an original holder of the Notes under this Agreement.

Section 22. MISCELLANEOUS.

Section 22.1. Successors and Assigns. All covenants and other agreements contained in this Agreement by or on behalf of any of the parties hereto bind and inure to the benefit of their respective successors and assigns (including, without limitation, any subsequent holder of a Note) whether so expressed or not.

Section 22.2. Payments Due on Non-Business Days. Anything in this Agreement or the Notes to the contrary notwithstanding (but without limiting the requirement in **Section 8.5** that the notice of any prepayment specify a Business Day as the date fixed for such prepayment), any payment of principal of or Make-Whole Amount or interest on any Note that is due on a date other than a Business Day shall be made on the next succeeding Business Day without including the additional days elapsed in the computation of the interest payable on such next succeeding Business Day; *provided* that if the maturity date of any Note is a date other than a Business Day, the payment otherwise due on such maturity date shall be made on the next succeeding Business Day and shall include the additional days elapsed in the computation of interest payable on such next succeeding Business Day.

Section 22.3. Accounting Terms. (a) All accounting terms used herein which are not expressly defined in this Agreement have the meanings respectively given to them in accordance with GAAP. Except as otherwise specifically provided herein, (i) all computations made pursuant to this Agreement shall be made in accordance with GAAP and (ii) all financial statements shall be prepared in accordance with GAAP. For purposes of determining compliance with the financial covenants contained in this Agreement, any election by the Company to measure an item of Indebtedness using fair value (as permitted by Accounting Standard Codification Topic No. 825-10-25 – Fair Value Option or any similar accounting standard) shall be disregarded and such determination shall be made as if such election had not been made.

(b) Notwithstanding the foregoing, if the Company notifies the holders of Notes that, in the Company's reasonable opinion, or if the Required Holders notify the Company that, in the Required Holders' reasonable opinion, as a result of a change in GAAP after the date of this Agreement, any covenant contained in **Section 10.1** through **10.6**, or any of the defined terms used therein no longer apply as intended such that such covenants are materially more or less restrictive to the Company than as at the date of this Agreement, the Company shall negotiate in good faith with the holders of Notes to make any necessary adjustments to such covenant or defined term to provide the holders of the Notes with substantially the same protection as such covenant provided prior to the relevant change in GAAP. Until the Company and the Required Holders so agree to reset, amend or establish alternative covenants or defined terms, (i) the covenants contained in **Section 10.1** through **10.6**, together with the relevant defined terms, shall continue to apply and compliance therewith shall be determined on the basis of GAAP in effect at the date of this Agreement and (ii) each set of financial statements delivered to holders of Notes pursuant to **Section 7.1(a)** or **(b)** during such time shall include detailed reconciliations reasonably satisfactory to the Required Holders as to the effect of such change in GAAP.

Section 22.4. Severability. Any provision of this Agreement that is prohibited or unenforceable in any jurisdiction shall, as to such jurisdiction, be ineffective to the extent of such prohibition or unenforceability without invalidating the remaining provisions hereof, and any such prohibition or unenforceability in any jurisdiction shall (to the full extent permitted by law) not invalidate or render unenforceable such provision in any other jurisdiction.

Section 22.5. Construction, Etc. Each covenant contained herein shall be construed (absent express provision to the contrary) as being independent of each other covenant contained herein, so that compliance with any one covenant shall not (absent such an express contrary provision) be deemed to excuse compliance with any other covenant. Where any provision herein refers to action to be taken by any Person, or which such Person is prohibited from taking, such provision shall be applicable whether such action is taken directly or indirectly by such Person.

For the avoidance of doubt, all Schedules and Exhibits attached to this Agreement shall be deemed to be a part hereof.

Section 22.6. Counterparts. This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together shall constitute one instrument. Each counterpart may consist of a number of copies hereof, each signed by less than all, but together signed by all, of the parties hereto.

Section 22.7. Governing Law. This Agreement shall be construed and enforced in accordance with, and the rights of the parties shall be governed by, the law of the State of New York, excluding choice-of-law principles of the law of such State that would permit the application of the laws of a jurisdiction other than such State.

*Section 22.8. Jurisdiction and Process; Waiver of Jury Trial***.** (a) The Company irrevocably submits to the non-exclusive jurisdiction of any New York State or federal court sitting in the Borough of Manhattan, The City of New York, over any suit, action or proceeding arising out of or relating to this Agreement or the Notes. To the fullest extent permitted by applicable law, the Company irrevocably waives and agrees not to assert, by way of motion, as a defense or otherwise, any claim that it is not subject to the jurisdiction of any such court, any objection that it may now or hereafter have to the laying of the venue of any such suit, action or proceeding brought in any such court and any claim that any such suit, action or proceeding brought in any such court has been brought in an inconvenient forum.

(b) The Company consents to process being served by or on behalf of any holder of Notes in any suit, action or proceeding of the nature referred to in **Section 22.8(a)** by mailing a copy thereof by registered or certified mail (or any substantially similar form of mail), postage prepaid, return receipt requested, to it at its address specified in **Section 18** or at such other address of which such holder shall then have been notified pursuant to said Section. The Company agrees that such service upon receipt (i) shall be deemed in every respect effective service of process upon it in any such suit, action or proceeding and (ii) shall, to the fullest extent permitted by applicable law, be taken and held to be valid personal service upon and personal delivery to it. Notices hereunder shall be conclusively presumed received as evidenced by a delivery receipt furnished by the United States Postal Service or any reputable commercial delivery service.

(c) Nothing in this **Section 22.8** shall affect the right of any holder of a Note to serve process in any manner permitted by law, or limit any right that the holders of any of the Notes may have to bring proceedings against the Company in the courts of any appropriate jurisdiction or to enforce in any lawful manner a judgment obtained in one jurisdiction in any other jurisdiction.

(d) The parties hereto hereby waive trial by jury in any action brought on or with respect to this Agreement, the Notes or any other document executed in connection herewith or therewith.

* * * * *

If you are in agreement with the foregoing, please sign the form of agreement on a counterpart of this Agreement and return it to the Company, whereupon this Agreement shall become a binding agreement between you and the Company.

Very truly yours,

KENTUCKY POWER COMPANY

By ______________________________
Name: Julia A. Sloat
Title: Treasurer

SCHEDULE B

DEFINED TERMS

As used herein, the following terms have the respective meanings set forth below or set forth in the Section hereof following such term:

"*Acquiring Person*" is defined in **Section 10.3(c).**

"*AEP*" means American Electric Power Company, Inc., a New York corporation.

"*Affiliate*" means, at any time, and with respect to any Person, any other Person that at such time directly or indirectly through one or more intermediaries Controls, or is Controlled by, or is under common Control with, such first Person, and with respect to the Company, shall include any Person beneficially owning or holding, directly or indirectly, 10% or more of any class of voting or equity interests of the Company or any Person of which the Company beneficially owns or holds, in the aggregate, directly or indirectly, 10% or more of any class of voting or equity interests. As used in this definition, "*Control*" means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through the ownership of voting securities, by contract or otherwise. Unless the context otherwise clearly requires, any reference to an "*Affiliate*" is a reference to an Affiliate of the Company.

"*Agreement*" means this Agreement, including all Schedules and Exhibits attached to this Agreement, as it may be amended, restated, supplemented or otherwise modified from time to time.

"*Anti-Corruption Laws*" is defined in **Section 5.16(d)(1)**.

"*Anti-Money Laundering Laws*" is defined in **Section 5.16(c)**.

"*Blocked Person*" is defined in **Section 5.16(a)**.

"*Business Day*" means (a) for the purposes of **Section 8.7** only, any day other than a Saturday, a Sunday or a day on which commercial banks in New York City are required or authorized to be closed, and (b) for the purposes of any other provision of this Agreement, any day other than a Saturday, a Sunday or a day on which commercial banks in New York, New York or Columbus, Ohio are required or authorized to be closed.

"*Capital Lease*" means, at any time, a lease with respect to which the lessee is required concurrently to recognize the acquisition of an asset and the incurrence of a liability in accordance with GAAP.

"*Change in Control*" is defined in **Section 8.3(g)**.

"*Change in Control Prepayment Event*" is defined in **Section 8.3(g)**.

"*CISADA*" is defined in **Section 5.16(a)**.

"*Closing*" is defined in **Section 3**.

"*Code*" means the Internal Revenue Code of 1986, as amended from time to time, and the rules and regulations promulgated thereunder from time to time.

"*Company*" means Kentucky Power Company, a Kentucky corporation, and any successor that becomes such in the manner prescribed in **Section 10.3**.

"*Confidential Information*" is defined in **Section 20**.

"*Consolidated Capital*" means the sum of (a) Consolidated Indebtedness and (b) the consolidated equity of all classes of stock (whether common, preferred, mandatorily convertible preferred or preference) of the Company, in each case determined in accordance with GAAP, but including Equity-Preferred Securities issued by the Company and its Subsidiaries.

"*Consolidated Indebtedness*" means the total principal amount of all Indebtedness described in clauses (a) through (e) of the definition of Indebtedness and Guaranties of such Indebtedness of the Company and its Subsidiaries, excluding, however, (a) Stranded Cost Recovery Bonds, (b) Equity-Preferred Securities not to exceed 10% of Consolidated Capital (calculated for purposes of this clause without reference to any Equity-Preferred Securities), and (c) any Indebtedness of the Company to any Subsidiary of the Company and any Indebtedness of such Subsidiary of the Company to the Company.

"*Control Event*" is defined in **Section 8.3(g)**.

"*Controlled Entity*" means (i) any of the Subsidiaries of the Company and any of their or the Company's respective Controlled Affiliates and (ii) if the Company has a parent company, such parent company and its Controlled Affiliates. As used in this definition, *"Control"* means the possession, directly or indirectly, of the power to direct or cause the direction of the management and policies of a Person, whether through the ownership of voting securities, by contract or otherwise.

"*Corporate Credit Rating*" is defined in **Section 8.3(g)**.

"*Credit Facility*" means any credit, revolving loan, note or other like agreement between the Company and one or more lenders or purchasers with the commitment from such lenders or purchasers to extend credit thereunder to the Company not being less than $50,000,000.

"*Default*" means an event or condition the occurrence or existence of which would, with the lapse of time or the giving of notice or both, become an Event of Default.

"*Default Rate*" means with respect to a series of Notes, that rate of interest per annum that is the greater of (i) 1% above the rate of interest stated in clause (a) of the first paragraph of the Notes of such series or (ii) 1% over the rate of interest publicly announced by Citibank N.A. in New York, New York as its "base" or "prime" rate.

"*Disclosure Documents*" is defined in **Section 5.3**.

"Electronic Delivery" is defined in **Section 7.4**.

"Environmental Laws" means any and all federal, state, local, and foreign statutes, laws, regulations, ordinances, rules, judgments, orders, decrees, permits, concessions, grants, franchises, licenses, agreements or governmental restrictions relating to pollution and the protection of the environment or the release of any materials into the environment, including but not limited to those related to Hazardous Materials.

"*Equity-Preferred Securities*" shall mean (a) debt or preferred securities that are mandatorily convertible or mandatorily exchangeable into common shares of the Company and (b) any other securities, however denominated, including but not limited to trust originated preferred securities, (i) issued by the Company or any of its consolidated Subsidiaries, (ii) that are not subject to mandatory redemption or the underlying securities, if any, of which are not subject to mandatory redemption, (iii) that are perpetual or mature no less than 30 years from the date of issuance, (iv) the indebtedness issued in connection with which, including any guaranty, is subordinate in right of payment to the unsecured and unsubordinated indebtedness of the issuer of such indebtedness or guaranty, and (v) the terms of which permit the deferral of the payment of interest or distributions thereon to a date occurring after the maturity date of the Notes.

"ERISA" means the Employee Retirement Income Security Act of 1974, as amended from time to time, and the rules and regulations promulgated thereunder from time to time in effect.

"ERISA Affiliate" means any trade or business (whether or not incorporated) that is treated as a single employer together with the Company under section 414 of the Code or under other applicable law.

"Event of Default" is defined in **Section 11**.

"Exchange Act" means the Securities Exchange Act of 1934, as amended from time to time, and the rules and regulations promulgated thereunder from time to time in effect.

"*First Closing*" is defined in Section 3.

"GAAP" means generally accepted accounting principles as in effect from time to time in the United States of America.

"Governmental Authority" means

(a) the government of

(i) the United States of America or any State or other political subdivision thereof, or

(ii) any other jurisdiction in which the Company or any Subsidiary conducts all or any part of its business, or which asserts jurisdiction over any properties of the Company or any Subsidiary, or

(b) any entity exercising executive, legislative, judicial, regulatory or administrative functions of, or pertaining to, any such government.

"*Governmental Official*" means any governmental official or employee, employee of any government-owned or government-controlled entity, political party, any official of a political party, candidate for political office, official of any public international organization or anyone else acting in an official capacity.

"Guaranty" of any Person means any obligation, contingent or otherwise, of such Person (a) to pay any Indebtedness of any other Person or (b) incurred in connection with the issuance by a third person of a Guaranty of Indebtedness of any other Person (whether such obligation arises by agreement to reimburse or indemnify such third Person or otherwise).

"Hazardous Materials" means any and all pollutants, toxic or hazardous wastes or any other substances, including all substances listed in or regulated in any Environmental Law that might pose a hazard to health and safety, the removal of which may be required or the generation, manufacture, refining, production, processing, treatment, storage, handling, transportation, transfer, use, disposal, release, discharge, spillage, seepage, or filtration of which is or shall be restricted, regulated, prohibited or penalized by any applicable law including, but not limited to, asbestos, urea formaldehyde foam insulation, polychlorinated biphenyls, petroleum, petroleum products, lead based paint, radon gas or similar restricted, prohibited or penalized substances.

"holder" means, with respect to any Note, the Person in whose name such Note is registered in the register maintained by the Company pursuant to **Section 13.1**, *provided, however*, that if such Person is a nominee, then for the purposes of **Sections 7, 12, 17.2** and **18** and any related definitions in this **Schedule B**, *"holder"* shall mean the beneficial owner of such Note whose name and address appears in such register.

"Indebtedness" with respect to any Person means, at any time, without duplication, (a) all indebtedness of such Person for borrowed money, (b) all obligations of such Person for the deferred purchase price of property or services (other than trade payables not overdue by more than 60 days incurred in the ordinary course of such Person's business), (c) all obligations of such Person evidenced by notes, bonds, debentures or other similar instruments, (d) all obligations of such Person as lessee under leases that have been, in accordance with GAAP, recorded as Capital Leases, (e) all obligations of such Person in respect of reimbursement agreements with respect to acceptances, letters of credit (other than trade letters of credit) or similar extensions of credit, (f) all Guaranties, (g) all reasonably quantifiable obligations under indemnities or under support or capital contribution agreements, and other reasonably quantifiable obligations (contingent or otherwise) to purchase or otherwise to assure a creditor against loss in respect of, or to assure an obligee against loss in respect of, all Indebtedness of others referred to in clauses (a) through (f) above guaranteed directly or indirectly in any manner by such Person, or in effect guaranteed directly or indirectly by such Person through an agreement (i) to pay or purchase such Indebtedness or to advance or supply funds for the payment or purchase of such Indebtedness, (ii) to purchase, sell or lease (as lessee or lessor) property, or to purchase or sell services, primarily for the purpose of enabling the debtor to make payment of such Indebtedness or to assure the holder of such Indebtedness against loss, (iii) to

supply funds to or in any other manner invest in the debtor (including any agreement to pay for property or services irrespective of whether such property is received or such services are rendered) or (iv) otherwise to assure a creditor against loss.

"*Institutional Investor*" means (a) any purchaser of a Note, (b) any holder of a Note holding (together with one or more of its affiliates) more than 5% of the aggregate principal amount of the Notes then outstanding, (c) any bank, trust company, savings and loan association or other financial institution, any pension plan, any investment company, any insurance company, any broker or dealer, or any other similar financial institution or entity, regardless of legal form, and (d) any Related Fund of any holder of any Note.

"*Investment Grade*" is defined in **Section 8.3(g)**.

"*Liens*" is defined in **Section 10.2**.

"*Make-Whole Amount*" is defined in **Section 8.7**.

"*Margin Stock*" shall have the meaning specified Regulation U of the Board of Governors of the Federal Reserve System (12 CFR 221).

"*Material*" means material in relation to the business, condition (financial or otherwise) or operations of the Company and its Subsidiaries taken as a whole.

"*Material Adverse Effect*" means a material adverse effect on (a) the business, condition (financial or otherwise) or operations of the Company and its Subsidiaries taken as a whole, or (b) the ability of the Company to perform its obligations under this Agreement and the Notes, or (c) the validity or enforceability of this Agreement or the Notes.

"*Memorandum*" is defined in **Section 5.3**.

"*Multiemployer Plan*" means any Plan that is a "multiemployer plan" (as such term is defined in section 4001(a)(3) of ERISA).

"*NAIC*" means the National Association of Insurance Commissioners or any successor thereto.

"*Negative Rating Event*" is defined in Section 8.3(g).

"*Net Tangible Assets*" is defined in **Section 10.2**.

"*Notes*" is defined in **Section 1**.

"*OFAC*" is defined in **Section 5.16(a)**.

"*OFAC Listed Person*" is defined in **Section 5.16(a)**.

"*OFAC Sanctions Program*" means any economic or trade sanction that OFAC is responsible for administering and enforcing. A list of OFAC Sanctions Programs may be found at http://www.treasury.gov/resource-center/sanctions/Programs/Pages/Programs.aspx.

"Officer's Certificate" means a certificate of a Senior Financial Officer or of any other officer of the Company whose responsibilities extend to the subject matter of such certificate.

"PBGC" means the Pension Benefit Guaranty Corporation referred to and defined in ERISA or any successor thereto.

"Person" means an individual, partnership, corporation, limited liability company, association, trust, unincorporated organization, business entity or Governmental Authority.

"Plan" means an "employee benefit plan" (as defined in section 3(3) of ERISA) subject to Title I of ERISA that is or, within the preceding five years, has been established or maintained, or to which contributions are or, within the preceding five years, have been made or required to be made, by the Company or any ERISA Affiliate or with respect to which the Company or any ERISA Affiliate may have any liability.

"property" or *"properties"* means, unless otherwise specifically limited, real or personal property of any kind, tangible or intangible, choate or inchoate.

"Proposed Prepayment Date" is defined in **Section 8.3(c)**.

"PTE" is defined in **Section 6.2(a)**.

"Purchaser" or "*Purchasers*" means each of the purchasers that has executed and delivered this Agreement to the Company and such Purchaser's successors and assigns (so long as any such assignment complies with Section 13.2); *provided*, *however*, that any Purchaser of a Note that ceases to be the registered holder or a beneficial owner (through a nominee) of such Note as the result of a transfer thereof pursuant to Section 13.2 shall cease to be included within the meaning of "Purchaser" of such Note for the purposes of this Agreement upon a transfer.

"QPAM Exemption" is defined in **Section 6.2(d)**.

"Qualified Institutional Buyer" means any Person who is a "qualified institutional buyer" within the meaning of such term as set forth in Rule 144A(a)(1) under the Securities Act.

"Rated Securities" is defined in **Section 8.3(g)**.

"Rating Agency" is defined in **Section 8.3(g)**.

"Rating Downgrade" is defined in **Section 8.3(g)**.

"Related Fund" means, with respect to any holder of any Note, any fund or entity that (a) invests in Securities or bank loans, and (b) is advised or managed by such holder, the same investment advisor as such holder or by an affiliate of such holder or such investment advisor.

"Required Holders" means, (a) prior to the Second Closing, the Purchasers and (b) at any time after the Second Closing, the holders of at least 51% in principal amount of the Notes (exclusive of Notes then owned by the Company or any of its Affiliates).

"Responsible Officer" means any Senior Financial Officer and any other officer of the Company with responsibility for the administration of the relevant portion of this Agreement.

"SEC" means the Securities and Exchange Commission of the United States, or any successor thereto.

"*Second Closing*" is defined in Section 3.

"Secured Debt" is defined in **Section 10.2**.

"Securities" or *"Security"* shall have the same meaning as in Section 2(1) of the Securities Act.

"Securities Act" means the Securities Act of 1933, as amended from time to time, and the rules and regulations promulgated thereunder from time to time in effect.

"Senior Financial Officer" means the chief financial officer, principal accounting officer, treasurer or comptroller of the Company.

"Series A Notes" is defined in **Section 1**.

"Series B Notes" is defined in **Section 1**.

"Significant Subsidiary" means, at any time, any Subsidiary of the Company that constitutes at such time a "significant subsidiary" of AEP, as such term is defined in Regulation S-X of the SEC as in effect on the date hereof (17 C.F.R. Part 210); *provided, however,* that "total assets" as used in Regulation S-X shall not include securitization transition assets on the balance sheet of any Subsidiary resulting from the issuance of transition bonds or other asset backed securities of a similar nature.

"*Stranded Cost Recovery Bonds"* means securities, however denominated, that are issued by the Company or any Subsidiary of the Company that are (a) non-recourse to the Company and its Significant Subsidiaries (other than for failure to collect and pay over the charges referred to in clause (b) below) and (b) payable solely from transition or similar charges authorized by law (including, without limitation, any "financing order", as such term is defined in the Texas Utilities Code) to be invoiced to customers of any Subsidiary of the Company or to retail electric providers.

"Subsidiary" means, as to any Person, any other Person in which such first Person or one or more of its Subsidiaries or such first Person and one or more of its Subsidiaries owns sufficient equity or voting interests to enable it or them (as a group) ordinarily, in the absence of contingencies, to elect a majority of the directors (or Persons performing similar functions) of such second Person, and any partnership or joint venture if more than a 50% interest in the profits or capital thereof is owned by such Person or one or more of its Subsidiaries or such first Person and one or more of its Subsidiaries (unless such partnership can and does ordinarily take major business actions without the prior approval of such Person or one or more of its Subsidiaries). Unless the context otherwise clearly requires, any reference to a "Subsidiary" is a reference to a Subsidiary of the Company.

"*Surviving Person*" is defined in **Section 10.3(b)**.

"*SVO*" means the Securities Valuation Office of the NAIC or any successor to such Office.

"*U.S. Economic Sanctions*" is defined in **Section 5.16(a)**.

"*USA Patriot Act*" means United States Public Law 107-56, Uniting and Strengthening America by Providing Appropriate Tools Required to Intercept and Obstruct Terrorism (USA PATRIOT ACT) Act of 2001, as amended from time to time, and the rules and regulations promulgated thereunder from time to time in effect.

"*Voting Stock*" means Securities of any class or classes, the holders of which are ordinarily, in the absence of contingencies, entitled to elect the corporate directors (or Persons performing similar functions).

"*Wholly-owned Subsidiary*" means, at any time, any Subsidiary one hundred percent (100%) of all of the equity interests (except directors' qualifying shares) and voting interests of which are owned by any one or more of the Company and the Company's other Wholly-owned Subsidiaries at such time.

SCHEDULE 5.3

DISCLOSURE MATERIALS

Kentucky Power Company 2011 Annual Report

Kentucky Power Company 2012 Annual Report

Kentucky Power Company 2013 Annual Report

Kentucky Power Company 2014 First Quarter Report

SCHEDULE 5.4

DIRECTORS AND SENIOR OFFICERS OF THE COMPANY

Directors:
Name:
Akins, Nicholas K.
Barton, Lisa M.
Feinberg, David M.
Hillebrand, Lana L
McCullough, Mark C.
Powers, Robert P.
Tierney, Brian X.
Welch, Dennis E.

Officers:

Name	**Title**
Nicholas K. Akins	Chairman of the Board & Chief Executive Officer
Gregory G. Pauley	President & Chief Operating Officer
Lisa M. Barton	Vice President
Bruce Evans	Vice President
Ronald K. Ford	Vice President-Regulatory & Finance
Lana L. Hillebrand	Vice President
Timothy K. Light	Vice President
Mark C. McCullough	Vice President
Robert P. Powers	Vice President
Mark A. Pyle	Vice President-Tax

Julio C. Reyes	Vice President-External Affairs
Scott N. Smith	Vice President
Brian X. Tierney	Vice President & Chief Financial Officer
Dennis E. Welch	Vice President
Joseph M. Buonaiuto	Controller & Chief Accounting Officer
David M. Feinberg	Secretary
Julia A. Sloat	Treasurer
F. Scott Travis	Assistant Controller
Julie Williams	Assistant Controller
Thomas G. Berkemeyer	Assistant Secretary
Jeffrey D. Cross	Assistant Secretary
Renee V. Hawkins	Assistant Treasurer

SCHEDULE 5.5

FINANCIAL STATEMENTS

Statements of Income for the Years Ended December 31, 2013, 2012 and 2011

Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the Years Ended December 31, 2013, 2012 and 2011

Balance Sheets December 31, 2013, 2012 and 2011

Statements of Cash Flows for the Years Ended December 31, 2013, 2012 and 2011

Unaudited Statements of Income for the Three Months Ended March 31, 2014 and 2013

Unaudited Statements of Changes in Common Shareholder's Equity and Comprehensive Income (Loss) for the Three Months Ended March 31, 2014 and 2013

Unaudited Balance Sheets March 31, 2014 and 2013

Unaudited Statements of Cash Flows for the Three Months Ended March 31, 2014 and 2013

Schedule 5.12(b)

Funding Target Attainment

For each of the Plans which is a pension plan within the meaning of Section 3(2) of ERISA (other than Multiemployer Plans) that is subject to the funding requirements of Section 302 of ERISA or Section 412 of the Code, the funding target attainment percentage as of January 1, 2013, determined on the basis of the actuarial assumptions specified for funding purposes in such Plan's actuarial valuation report for the plan year beginning January 1, 2013, is:

- For the American Electric Power System Retirement Plan: 100.16%

Schedule 5.12(d)

2013 Accumulated Post Retirement Benefit Obligation

There is no unfunded accumulated post-retirement benefit obligation (APBO) of the Company as determined as of December 31, 2013, in accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 715-60 for retiree medical and life insurance plans, without regard to liabilities attributable to continuation coverage mandated by Section 4980B of the Code, as there is a net surplus position.

SCHEDULE 5.15

EXISTING INDEBTEDNESS

The following details long-term debt outstanding at July 10, 2014:

TYPE OF DEBT	MATURITY	INTEREST RATES AT JULY 10, 2014	BALANCE AT JULY 10, 2014 (a)
Senior Unsecured Notes, Series D	2032	5.625%	$75,000
Senior Unsecured Notes, Series E	2017	6.000%	$325,000
Senior Unsecured Notes, Series A	2021	7.250%	$40,000
Senior Unsecured Notes, Series B	2029	8.030%	$30,000
Senior Unsecured Notes, Series C	2039	8.130%	$60,000
Term Loan Debt	2015	Floating	200,000
Unamortized Premium (Discount) as of May 31, 2014			($541,856)
Total Non-Affiliated Debt			$729,458
Intercompany Notes	2015	5.250%	$20,000
Total Long-term Debt			$749,458
Less: Long-term Debt Due Within One Year			($200,000)
Long-term Debt			$549,548

(a) Balance at July 10, 2014 in thousands

Short-term debt as of June 30, 2013 was $0.

EXHIBIT 1-A

FORM OF SERIES A NOTE

This Note has not been registered under the Securities Act of 1933, as amended, and may not be transferred, sold or otherwise disposed of except while registration under said Act is in effect or pursuant to an exemption from registration under said Act or if said Act does not apply.

KENTUCKY POWER COMPANY

4.18% Senior Note, Series A, due September 30, 2026

No. _________ [Date]
$____________ PPN 491386 D*6

FOR VALUE RECEIVED, the undersigned, KENTUCKY POWER COMPANY (herein called the *"Company"*), a corporation organized and existing under the laws of the State of Kentucky, hereby promises to pay to [________________], or registered assigns, the principal sum of [________________] DOLLARS (or so much thereof as shall not have been prepaid) on September 30, 2026, with interest (computed on the basis of a 360-day year of twelve 30-day months) on the unpaid balance hereof at the rate of (a) 4.18% per annum from the date hereof, payable semiannually, on the 30th day of March and September in each year, commencing with the March 30 or September 30 next succeeding the date hereof, until the principal hereof shall have become due and payable, and (b) to the extent permitted by law, on any overdue payment of interest and, during the continuance of an Event of Default, on such unpaid balance and on any overdue payment of any Make-Whole Amount, at a rate per annum from time to time equal to the greater of (i) 5.18% or (ii) 1% over the rate of interest publicly announced by Citibank N.A. from time to time in New York, New York as its "base" or "prime" rate payable semiannually as aforesaid (or, at the option of the registered holder hereof, on demand).

Payments of principal of, interest on and any Make-Whole Amount with respect to this Note are to be made in lawful money of the United States of America at Citibank, N.A. in New York, New York or at such other place as the Company shall have designated by written notice to the holder of this Note as provided in the Note Purchase Agreement referred to below.

This Note is one of a series of Senior Notes (herein called the *"Notes"*), issued pursuant to the Note Purchase Agreement, dated as of July 10, 2014 (as from time to time amended, the *"Note Purchase Agreement"*), among the Company and the Purchasers named therein and is entitled to the benefits thereof. Each holder of this Note will be deemed, by its acceptance hereof, to have (i) agreed to the confidentiality provisions set forth in **Section 20** of the Note Purchase Agreement and (ii) made the representation set forth in **Section 6.2** of the Note Purchase Agreement. Unless otherwise indicated, capitalized terms used in this Note shall have the respective meanings ascribed to such terms in the Note Purchase Agreement.

This Note is a registered Note and, as provided in the Note Purchase Agreement, upon surrender of this Note for registration of transfer, duly endorsed, or accompanied by a written instrument of transfer duly executed, by the registered holder hereof or such holder's attorney duly authorized in writing, a new Note for a like principal amount will be issued to, and registered in the name of, the transferee. Prior to due presentment for registration of transfer, the Company may treat the person in whose name this Note is registered as the owner hereof for the purpose of receiving payment and for all other purposes, and the Company will not be affected by any notice to the contrary.

This Note is subject to optional prepayment, in whole or from time to time in part, at the times and on the terms specified in the Note Purchase Agreement, but not otherwise.

If an Event of Default occurs and is continuing, the principal of this Note may be declared or otherwise become due and payable in the manner, at the price (including any applicable Make-Whole Amount) and with the effect provided in the Note Purchase Agreement.

This Note shall be construed and enforced in accordance with, and the rights of the Company and the holder of this Note shall be governed by, the law of the State of New York, excluding choice-of-law principles of the law of such State that would permit application of the laws of a jurisdiction other than such State.

KENTUCKY POWER COMPANY

By ____________________________________
Title:

EXHIBIT 1-B

FORM OF SERIES B NOTE

This Note has not been registered under the Securities Act of 1933, as amended, and may not be transferred, sold or otherwise disposed of except while registration under said Act is in effect or pursuant to an exemption from registration under said Act or if said Act does not apply.

KENTUCKY POWER COMPANY

4.33% Senior Note, Series B, due December 30, 2026

No. [_________]	[Date]
$[____________]	PPN 491386 D@4

FOR VALUE RECEIVED, the undersigned, KENTUCKY POWER COMPANY (herein called the *"Company"*), a corporation organized and existing under the laws of the State of Kentucky, hereby promises to pay to [________________], or registered assigns, the principal sum of [________________] DOLLARS (or so much thereof as shall not have been prepaid) on December 30, 2026, with interest (computed on the basis of a 360-day year of twelve 30-day months) on the unpaid balance hereof at the rate of (a) 4.33% per annum from the date hereof, payable semiannually, on the 30th day of June and December in each year, commencing with the June 30 or December 30 next succeeding the date hereof, until the principal hereof shall have become due and payable, and (b) to the extent permitted by law, on any overdue payment of interest and, during the continuance of an Event of Default, on such unpaid balance and on any overdue payment of any Make-Whole Amount, at a rate per annum from time to time equal to the greater of (i) 5.33% or (ii) 1% over the rate of interest publicly announced by Citibank N.A. from time to time in New York, New York as its "base" or "prime" rate payable semiannually as aforesaid (or, at the option of the registered holder hereof, on demand).

Payments of principal of, interest on and any Make-Whole Amount with respect to this Note are to be made in lawful money of the United States of America at Citibank, N.A. in New York, New York or at such other place as the Company shall have designated by written notice to the holder of this Note as provided in the Note Purchase Agreement referred to below.

This Note is one of a series of Senior Notes (herein called the *"Notes"*) issued pursuant to the Note Purchase Agreement, dated as of July 10, 2014 (as from time to time amended, the *"Note Purchase Agreement"*), among the Company and the Purchasers named therein and is entitled to the benefits thereof. Each holder of this Note will be deemed, by its acceptance hereof, to have (i) agreed to the confidentiality provisions set forth in **Section 20** of the Note Purchase Agreement and (ii) made the representation set forth in **Section 6.2** of the Note Purchase Agreement. Unless otherwise indicated, capitalized terms used in this Note shall have the respective meanings ascribed to such terms in the Note Purchase Agreement.

This Note is a registered Note and, as provided in the Note Purchase Agreement, upon surrender of this Note for registration of transfer, duly endorsed, or accompanied by a written instrument of transfer duly executed, by the registered holder hereof or such holder's attorney duly authorized in writing, a new Note for a like principal amount will be issued to, and registered in the name of, the transferee. Prior to due presentment for registration of transfer, the Company may treat the person in whose name this Note is registered as the owner hereof for the purpose of receiving payment and for all other purposes, and the Company will not be affected by any notice to the contrary.

This Note is subject to optional prepayment, in whole or from time to time in part, at the times and on the terms specified in the Note Purchase Agreement, but not otherwise.

If an Event of Default occurs and is continuing, the principal of this Note may be declared or otherwise become due and payable in the manner, at the price (including any applicable Make-Whole Amount) and with the effect provided in the Note Purchase Agreement.

This Note shall be construed and enforced in accordance with, and the rights of the Company and the holder of this Note shall be governed by, the law of the State of New York, excluding choice-of-law principles of the law of such State that would permit application of the laws of a jurisdiction other than such State.

KENTUCKY POWER COMPANY

By ____________________________________
Title

EXHIBIT 4.4(a)

FORM OF OPINION OF COUNSEL
TO THE COMPANY

To the Parties listed
On the Attached Schedule

________, 2014

Re: Kentucky Power Company

Ladies and Gentlemen:

I am Deputy General Counsel in the Legal Department of American Electric Power Service Corporation, a New York corporation ("AEPSC") and subsidiary of American Electric Power Company, Inc. ("AEP") and an affiliate of Kentucky Power Company, a Kentucky corporation ("KPC"), and have acted as counsel to KPC, in connection with (i) the execution and delivery of the Note Purchase Agreement, dated as of July 10, 2014 (the "Note Purchase Agreement") among KPC and you, as purchasers (each, a "Purchaser" and, collectively, the "Purchasers"); and (ii) the execution and delivery by KPC of (a) $120,000,000 aggregate principal amount of the Company's 4.18% Senior Notes, Series A, due September 30, 2026, and (b) $80,000,000 aggregate principal amount of the Company's 4.33% Senior Notes, Series B, due December 30, 2026 (collectively, the "Notes", and together with the Note Purchase Agreement, the "Operative Agreements"). Capitalized terms not otherwise defined herein shall have the meanings specified in Schedule B to the Note Purchase Agreement.

I, or attorneys over whom I exercise supervision, have examined executed counterparts of the Operative Agreements, Certificate of KeyBanc Capital Markets Inc. and RBS Securities Inc., dated the date hereof (the "Certificate"), delivered in connection with the Operative Agreements certifying that the Notes have been offered only to a limited number of institutional investors, and have also examined originals or copies of such agreements and other instruments and records, certificates of public officials and of officers of the KPC and such other documents and instruments as I have deemed relevant and necessary as a basis for the opinions expressed below. In making such examination, I, or attorneys over whom I exercise supervision, have assumed without investigation, the legal capacity of all natural persons, the genuineness of signatures (other than signatures on behalf of KPC), the authenticity, accuracy, and completeness of all documents submitted to me as originals and the conformity to original documents of all documents submitted to me as certified, photostatic or facsimile copies. I, or attorneys over whom I exercise supervision, have further assumed that each document furnished by a Governmental Authority is accurate, complete and authentic and all official records are accurate and complete.

In connection with the opinions rendered herein, I have relied (where such reliance is reasonable but without independent inquiry) upon the representations of the parties made in the Operative

Agreements, and upon certificates of KPC or of its officers, and on certificates of public officials.
I have assumed, with your permission and without investigation, the due execution and delivery of the Note Purchase Agreement by each party thereto (other than KPC).

Based on the foregoing and having due regard for such legal considerations as I deem relevant, and subject to the further qualifications, limitations, exceptions and assumptions hereinafter set forth, I am of the opinion that:

1. KPC is a corporation duly organized, legally existing and in good standing under the laws of the Commonwealth of Kentucky, and KPC has full right, power and authority to enter into and perform the Operative Agreements. KPC is duly authorized to conduct its business in each jurisdiction in which it operates and is duly qualified and is in good standing as a foreign corporation in each jurisdiction where the character of its properties or the nature of its activities makes such qualification necessary except where the failure to be so qualified will not have a material adverse effect on the business, properties or condition (financial or otherwise) of KPC.

2. The Operative Agreements have been duly authorized, executed and delivered by KPC and constitute legal, valid and binding obligations, contracts and agreements of KPC enforceable in accordance with their terms.

3. No approval, consent or authorization on the part of any regulatory body, Federal, state or local, is necessary as a condition to the lawful execution and delivery by KPC of the Operative Agreements, <u>except for authorizations or approvals</u> (i) as have already been obtained by KPC, are in full force and effect, have not been revoked or amended, are not the subject of any pending or, to the best of my knowledge, threatened attack on appeal or by direct proceedings or otherwise, (ii) as may be required under state securities or Blue Sky laws in connection with the purchase of the Notes by the Purchasers and (iii) as are not required to be made until after closing of the purchase and sale of the Notes.

4. The execution, delivery and performance by KPC of the Operative Agreements will not violate any provisions of any Kentucky or Federal statutes, laws, rules or regulations or any order or decree of any court or governmental authority or agency and will not conflict with nor result in any breach of any of the provisions of, or constitute a default under, or result in the creation of any lien upon any property of KPC under the provisions of any agreement, charter, instrument, by-law or other instrument to which KPC is a party or by which it may be bound.

5. (i) Assuming (a) the accuracy of the representations of the Purchasers set forth in Section 6 of the Note Purchase Agreement and (b) the accuracy of the representations made in the Certificate, the offer, sale and delivery of the Notes to the Purchasers in the manner contemplated by the Note Purchase Agreement constitute exempted transactions under the registration provisions of the Securities Act of 1933 and do not require any registration thereof under the Securities Act of 1933 (it being understood that I express no opinion as to any subsequent resale of any Notes).

6. KPC is not an "investment company" or a company "controlled" by an "investment company" under the Investment Company Act of 1940, as amended.

7. The issuance of the Notes and the use of the proceeds of the sale of the Notes in accordance with the provisions of and contemplated by the Note Purchase Agreement do not violate or conflict with Regulation T, U or X of the Board of Governors of the Federal Reserve System.

8. Except as disclosed in the Annual Report for the year ended December 31, 2013 and the Quarterly Report dated March 31, 2014, there are no proceedings pending or, to my knowledge after due inquiry, threatened, against or affecting KPC in any court or before any governmental authority or arbitration board or tribunal which if adversely determined would individually or in the aggregate materially and adversely affect the business or properties of KPC or the ability of KPC to perform its obligations under the Operative Agreements.

9. In any action or proceeding arising out of or relating to the Notes and the Note Purchase Agreement in any court of the Commonwealth of Kentucky or in any Federal court sitting in the Commonwealth of Kentucky, such court would recognize and give effect to the provisions thereof wherein the parties thereto agree that the Notes and the Note Purchase Agreement shall be governed by, and construed in accordance with, the laws of the State of New York. However, if a court of the Commonwealth of Kentucky or a Federal court sitting in the Commonwealth of Kentucky were to hold that the Notes and the Note Purchase Agreement are governed by, and to be construed in accordance with, the laws of the State of Texas, the Notes and the Note Purchase Agreement would be, under the Commonwealth of Kentucky, the legal, valid and binding obligation of KPC, enforceable against KPC in accordance with their terms, subject to (i) applicable bankruptcy, insolvency, reorganization, fraudulent transfer and conveyance, voidable preference, moratorium, receivership, conservatorship, arrangement, or similar laws, and related regulations and judicial doctrines, from time to time in effect affecting creditors' rights and remedies generally, and (ii) general principles of equity (including, without limitation, standards of materiality, good faith, fair dealing, and reasonableness, equitable defenses, the exercise of judicial discretion, and limits on the availability of equitable remedies), whether such principles are considered in a proceeding at law or in equity.

The opinions expressed in paragraph 2 above are subject to the qualification that the enforceability of the obligations are subject to (i) applicable bankruptcy, insolvency, reorganization, fraudulent transfer and conveyance, voidable preference, moratorium, receivership, conservatorship, arrangement, or similar laws, and related regulations and judicial doctrines, from time to time in effect affecting creditors' rights and remedies generally, and (ii) general principles of equity (including, without limitation, standards of materiality, good faith, fair dealing, and reasonableness, equitable defenses, the exercise of judicial discretion, and limits on the availability of equitable remedies), whether such principles are considered in a proceeding at law or in equity. In addition, in connection with my enforceability opinions set forth in paragraph 2 above, I express no opinion with respect to provisions of the Operative Agreements purporting to waive or not give effect to legal defenses that cannot be waived under applicable law or other rights or benefits that cannot be waived under applicable law. Further, I am a member of the Bar of the States of New York and Ohio and do not purport to be expert on the laws of any jurisdiction other than the laws of the States of New York and Ohio and the Federal laws of the United States of America, and for purposes of paragraphs 1, 2, 3, 4 and 9 of this opinion only, Kentucky. I express no opinion as to any laws of any jurisdiction other than the laws of the States of New York and Ohio and the Federal law of the United States of America, and for purposes of paragraphs 1, 2, 3, 4 and 9 of this opinion only, Kentucky.

In rendering the foregoing opinion in paragraph 5 hereof, I have relied, insofar as securities matters are concerned, in part, on the Certificate executed and delivered by KeyBanc Capital Markets Inc. and RBS Securities Inc. (the only persons authorized or employed by KPC as agent, broker, dealer or otherwise in connection with the offering or sale of the Notes or any similar Security) and delivered to KPC.

In addition, I express no opinion as to the enforceability of indemnification agreements provided in the Operative Agreements, to the extent such enforceability may be barred or limited by considerations of public policy.

This opinion is rendered solely for your benefit in connection with the above-described transaction and may not be used, circulated, quoted, relied upon or otherwise referred to by any other person (except that any permitted subsequent holders of the Notes may rely hereon) for any other purpose without my prior written consent; provided that, Winston & Strawn LLP, special counsel for the Purchasers, may rely on the opinions expressed in this opinion letter in connection with the opinion to be furnished by them in connection with the above-described transactions; and provided further, that any of the Purchasers and any permitted subsequent holders of the Notes may furnish a copy hereof (but no such person shall be entitled to rely thereon) (i) to its independent auditors and attorneys, (ii) to any state or federal authority or independent banking, insurance board (including the NAIC) or body having regulatory jurisdiction over it, (iii) pursuant to order or legal process of any court or governmental agency, (iv) in connection with any legal action to which it is a party arising out of or in respect of any Note or the Note Purchase Agreement and (v) any potential transferee of the Notes. I undertake no responsibility to update or supplement this opinion in response to changes in law or future events or circumstances.

Very truly yours,

Jeffrey D. Cross
Counsel for Kentucky Power Company

EXHIBIT 4.4(b)

FORM OF OPINION OF SPECIAL COUNSEL TO THE PURCHASERS

______, 2014

To the Purchasers listed on Schedule I
attached hereto

Re: Kentucky Power Company
$120,000,000 4.18% Senior Notes, Series A, due September 30, 2026
$80,000,000 4.33% Senior Notes, Series B, due December 30, 2026

Ladies and Gentlemen:

We have acted as your special counsel in connection with (i) the issuance by Kentucky Power Company, a corporation formed under the laws of the State of Kentucky (the "Issuer"), of its Series A and Series B Senior Notes, in an aggregate principal amount of $200,000,000 (collectively, the "Notes"), and (ii) the purchase by you pursuant to the Note Purchase Agreement among the Purchasers named therein and the Issuer, to be dated as of the date hereof (the "Note Purchase Agreement") of Notes in the principal amounts set forth in Schedule A to the Note Purchase Agreement. All capitalized terms used herein and not otherwise defined shall have the meanings ascribed thereto in the Note Purchase Agreement. This opinion letter is delivered to you pursuant to the provisions of Section 4.4(b) of the Note Purchase Agreement.

In rendering the opinions set forth herein, we have examined:

(i) the Note Purchase Agreement;

(ii) the Notes (the items identified in clauses (i) and (ii) are collectively hereinafter referred to as the "Transaction Documents"); and such other agreements, instruments and documents, and such questions of law as we have deemed necessary or appropriate to enable us to render the opinions expressed below.

Additionally, we have examined originals or copies, certified to our satisfaction, of such certificates of public officials and officers of the Issuer, and we have made such inquiries of officers of the Issuer as we have deemed relevant or necessary, as the basis for the opinions set forth herein. As to questions of fact material to such opinions we have, when relevant facts were not independently established, relied upon the representations made in the Transaction Documents and upon certifications made by officers and other representatives of the Issuer.

In rendering the opinions expressed below, we have, with your consent, assumed (i) that the Transaction Documents have been duly authorized, executed and delivered by each party thereto, (ii) that the consummation of the transactions contemplated in the Transaction Documents has been duly authorized by the Issuer, (iii) the legal capacity of all natural persons executing documents, (iv) that the signatures of persons signing all documents in connection with which this opinion letter is rendered are genuine, (v) all documents submitted to us as originals or duplicate originals are authentic and (vi) all documents submitted to us as copies, whether certified or not, conform to authentic original documents. Additionally, we have, with your consent, assumed and relied upon, the following:

(a) the accuracy and completeness of all certificates and other statements, documents, records, financial statements and papers reviewed by us, and the accuracy and completeness of all representations, warranties, schedules and exhibits contained in the Transaction Documents, with respect to the factual matters set forth therein;

(b) all parties to the documents reviewed by us are duly organized, validly existing and in good standing under the laws of their respective jurisdictions of incorporation or formation and under the laws of all jurisdictions where they are conducting their businesses or otherwise required to be so qualified, and have full power and authority to execute, deliver and perform under such documents and all such documents have been duly authorized, executed and delivered by such parties; and

(c) because a claimant bears the burden of proof required to support its claims, the Purchasers will undertake the effort and expense necessary to fully present their claims in the prosecution of any right or remedy accorded the Purchasers under the Transaction Documents.

Based upon the foregoing and subject to the qualifications, limitations and comments stated herein, we are of the opinion that:

1. The Transaction Documents constitute the valid and binding obligations of the Issuer, enforceable against the Issuer in accordance with their respective terms.

2. It was not necessary in connection with the offering, issuance, sale and delivery of the Notes, under the circumstances contemplated by the Note Purchase Agreement, to register said Notes under the Securities Act of 1933, as amended, or to qualify an indenture in respect of said Notes under the Trust Indenture Act of 1939, as amended.

3. Neither the execution or delivery by the Issuer of the Transaction Documents nor the performance by the Issuer of its obligations thereunder requires the consent or approval of, or any filing or registration with, any governmental body, agency or authority of the State of New York or the United States of America other than any consents, approvals or filings required in connection with the exercise by any Purchaser of certain remedies under the Transaction Documents to the extent required pursuant to the terms thereof.

4. The opinion letter dated today of internal counsel to American Electric Power Service Corporation, an affiliate of the Issuer and delivered to you pursuant to Section 4.4(a) of the Note Purchase Agreement is satisfactory to us in form and scope with respect to the matters covered thereby and in our opinion you are justified in relying thereon.

The opinions as expressed herein are subject to the following qualifications, limitations and comments:

(a) the enforceability of the Transaction Documents is and the obligations of the Issuer under the Transaction Documents and the availability of certain rights and remedial provisions provided for in the Transaction Documents are subject to (1) judicial action giving effect to foreign governmental actions or foreign laws, in either case, affecting creditors' rights, (2) the effect of bankruptcy, fraudulent conveyance or transfer, insolvency, reorganization, arrangement, liquidation, conservatorship, and moratorium laws, (3) limitations imposed by other laws and judicial decisions relating to or affecting the rights of creditors or secured creditors generally, and (4) general principles of equity (regardless of whether enforcement is considered in proceedings at law or in equity), upon the availability of injunctive relief or other equitable remedies, including, without limitation, where (A) the breach of such covenants or provisions imposes restrictions or burdens upon a debtor and it cannot be demonstrated that the enforcement of such remedies, restrictions or burdens is reasonably necessary for the protection of a creditor; (B) a creditor's enforcement of such remedies, covenants or provisions under the circumstances, or the manner of such enforcement, would violate such creditor's implied covenant of good faith and fair dealing, or would be commercially unreasonable; or (C) a court having jurisdiction finds that such remedies, covenants or provisions were, at the time made, or are in application, unconscionable as a matter of law or contrary to public policy;

(b) as to our opinions set forth in paragraph 1 hereof, we express no opinion as to the enforceability of cumulative remedies to the extent such cumulative remedies purport to or would have the effect of compensating the party entitled to the benefits thereof in amounts in excess of the actual loss suffered by such party;

(c) we express no opinion as to the validity, binding effect or enforceability of any indemnification provisions of the Transaction Documents to the extent such obligations are contrary to applicable law or public policy or require an indemnification of a party for its own actions or inactions, to the extent such action or inaction involves gross negligence, recklessness, willful misconduct or unlawful conduct;

(d) requirements in the Transaction Documents specifying that provisions thereof may only be waived in writing may not be valid, binding or enforceable to the extent that an oral agreement or an implied agreement by trade practice or course of conduct has been created modifying any provision of such documents;

(e) we express no opinion with respect to the validity, binding effect or enforceability of any purported waiver, release or disclaimer under any of the Transaction Documents relating to statutory or equitable rights and defenses of the parties which are not subject to waiver, release or disclaimer;

(f) we express no opinion with respect to the applicability or effect of federal or state anti-trust, tax, and except as to matters covered in paragraph 2, securities or "blue sky" laws with respect to the transactions contemplated by the Transaction Documents;

(g) we express no opinion regarding the severability of any provision contained in the Transaction Documents;

(h) we express no opinion with respect to the validity, binding effect or enforceability of any provision of the Transaction Documents (i) purporting to establish consent to jurisdiction, insofar as it purports to confer subject matter jurisdiction on a United States District Court to adjudicate any controversy relating to such Transaction Documents in any circumstance in which such court would not have subject matter jurisdiction, (ii) the waiver of inconvenient forum with respect to proceedings in such United States District Court or (iii) the waiver of the right to jury trial;

(i) in rendering the opinions expressed in paragraph 2 hereof, we have assumed the accuracy of the representations and warranties of the Purchasers in the Note Purchase Agreement and representations by Keybanc Capital Markets Inc.. and RBS Securities Inc.. as to, *inter alia*, the number of offerees of the Notes. Further, we have assumed that no form of general solicitation or general advertising was used or will be used in connection with the offering of the Notes;

(j) our opinion with respect to the enforceability of the choice of law provisions of the Transaction Documents in paragraph 1 above is rendered in reliance on Section 5-1401 of the New York General Obligations Law and is subject to the qualifications that such enforceability (i) may be limited by public policy considerations of any jurisdiction, other than the State of New York, in which enforcement of such provisions, or of a judgment upon an agreement containing such provisions, is sought and (ii) does not apply to the extent provided in Section 1-105(2) of the Uniform Commercial Code as in effect in New York. Accordingly, we express no opinion as to the effect of the law of any jurisdiction (other than the State of New York) as to the choice of law in the Transaction Documents (including, without limitation, whether any court outside the State of New York would honor the choice of New York law as the governing law of the Transaction Documents);

(k) we express no opinion as to the effect of the law of any jurisdiction (other than New York) wherein any party seeking enforcement of any Transaction Document may be located or wherein the enforcement of any Transaction Document may be sought that limits the rates of interest legally chargeable or collectable; and

(m) we express no opinion with respect to the enforceability of any indemnity against loss in converting into a specified currency the proceeds or amount of a court judgment in another currency.

The opinions expressed herein are based upon and are limited to the laws of the State of New York and the laws of the United States of America and we express no opinion with respect to the laws of any other state, jurisdiction or political subdivision. The opinions expressed herein based on the laws of the State of New York and the United States of America are limited to the laws generally applicable in transactions of the type covered by the Transaction Documents.

Our opinions set forth in this letter are based upon the facts in existence and laws in effect on the date hereof and we expressly disclaim any obligation to update our opinions herein, regardless of whether changes in such facts or laws come to our attention after the delivery hereof.

This opinion letter is rendered only to the Purchasers and is solely for their benefit in connection with the execution and delivery of the Notes and for the benefit of any institutional investor transferee of the Notes; *provided* that any such transfer of the Notes is made and consented to in accordance with the express provisions of Section 13.2 of the Note Purchase Agreement, on the condition and understanding that (i) this opinion letter speaks only as of the date hereof, (ii) we have no responsibility or obligation to update this letter, to consider its applicability or correctness to other than its addressees, or to take into account changes in law, facts or any other developments of which we may later become aware, and (iii) any such reliance by a future transferee must be actual and reasonable under the circumstances existing at the time of transfer, including any changes in law, facts or any other developments known to or reasonably knowable by the transferee at such time. This opinion letter may not be relied upon in any manner by any other person and may not be disclosed, quoted, filed with a governmental agency or otherwise referred to without our prior written consent, except that the Purchasers (i) may deliver a copy of this opinion letter to such institutional investor transferee and (ii) may furnish a copy of this opinion letter to the National Association of Insurance Commissioners, applicable regulatory authorities or as may otherwise be required by law, court order or subpoena.

Very truly yours,

NEW ISSUE - BOOK ENTRY ONLY

In the opinion of Squire Patton Boggs (US) LLP, Bond Counsel, under existing law (i) assuming continuing compliance with certain covenants and the accuracy of certain representations, interest on the Bonds is excluded from gross income for federal income tax purposes, except interest on any Bond for any period during which it is held by a "substantial user" or a "related person," as those terms are used in Section 147(a) of the Internal Revenue Code of 1986, as amended (the "Code"), (ii) interest on the Bonds is an item of tax preference under Section 57 of the Code for purposes of the federal alternative minimum tax imposed on individuals and corporations, and (iii) the Bonds, and all interest and income thereon, are exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. Interest on the Bonds may be subject to certain federal taxes imposed only on certain corporations. See TAX EXEMPTION.

$65,000,000
West Virginia Economic Development Authority
Solid Waste Disposal Facilities Revenue Refunding Bonds
(Kentucky Power Company – Mitchell Project),
Series 2014A

Interest to accrue from date of issuance — Due: April 1, 2036

The Series 2014A Bonds (the "Bonds") are limited obligations of the West Virginia Economic Development Authority (the "Issuer"), and do not constitute an indebtedness or a charge against the general credit of the Issuer or the State of West Virginia. The Bonds are payable solely from, and secured by a pledge of, the loan repayments under a note issued under the terms of a Loan Agreement (the "Agreement") between the Issuer and

KENTUCKY POWER COMPANY

(the "Company") and from funds drawn under an irrevocable direct pay letter of credit (the "Letter of Credit") issued by

SUMITOMO MITSUI BANKING CORPORATION

The Letter of Credit will permit the Trustee, The Bank of New York Mellon Trust Company, N.A., to draw up to (a) an amount sufficient to pay (i) the principal of the Bonds when due at maturity or upon redemption or acceleration and (ii) the portion of the purchase price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the principal amount of such Bonds, plus (b) an amount equal to 35 days' interest on the Bonds at a maximum rate of 12% per annum to pay (i) interest on the Bonds when due and (ii) the portion of the purchase price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the accrued interest on such Bonds. The Letter of Credit will expire on June 26, 2017 or on the earliest occurrence of one or more of the events described herein, unless extended by Sumitomo Mitsui Banking Corporation (the "Letter of Credit Bank") (see *THE LETTER OF CREDIT AND REIMBURSEMENT AGREEMENT-- The Letter of Credit* herein). Unless the Letter of Credit is replaced or extended as described herein, the Bonds will be subject to mandatory purchase prior to its expiration.

The Bonds will initially bear interest at a Weekly Rate determined by the Remarketing Agent (as defined herein) as described under *THE BONDS -- Form and Denomination of Bonds; Payments on the Bonds -- Interest* herein, payable on the first Business Day of each month commencing July 1, 2014. Upon satisfaction of the conditions specified in the Indenture, the Company may from time to time change the interest rate determination method for the Bonds to a Daily Rate, a Weekly Rate or certain other interest rate modes provided for in the Indenture.

The Bonds are subject to mandatory tender and redemption as described under *THE BONDS – Mandatory Tender for Purchase* and *THE BONDS -- Redemption of Bonds* herein. When a Daily Rate or Weekly Rate is in effect for the Bonds, holders of the Bonds will have the option to tender their Bonds for purchase as described under *THE BONDS -- Optional Tender* herein.

While the Bonds bear interest at a Daily Rate or a Weekly Rate they will be issued as fully registered bonds in denominations of $100,000 and any larger denominations constituting an integral multiple of $5,000. The Bonds will be issued pursuant to an Indenture of Trust (the "Indenture"), between the Issuer and The Bank of New York Mellon Trust Company, N.A., as trustee (the "Trustee"). The Bonds will be issued as fully registered bonds and will be registered initially in the name of Cede & Co., as registered owner and nominee for The Depository Trust Company, New York, New York ("DTC"). DTC acts as a securities depository for the Bonds. Except under the limited circumstances described herein, Beneficial Owners of book-entry interests in Bonds will not receive certificates representing their interests. Payments of principal or purchase price of and interest on the Bonds will be made through DTC and disbursements of such payments to Beneficial Owners will be the responsibility of DTC and its Participants. See *THE BONDS – Book-Entry Only System* herein. U.S. Bank Municipal Securities Group, a Division of U.S. Bank National Association, will act as underwriter (the "Underwriter") for the Bonds. U.S. Bancorp Investments, Inc. and U.S. Bank Municipal Securities Group, a Division of U.S. Bank National Association, will act as remarketing agent (the "Remarketing Agent") for the Bonds.

PRICE: 100%

This cover page contains limited information for quick reference only and is not a summary of this Official Statement. Investors should read the entire Official Statement to obtain information essential to the making of an informed investment decision.

The Bonds are offered, subject to prior sale, when, as and if issued and received by the Underwriter, subject to the approval of their validity by Squire Patton Boggs (US) LLP, Bond Counsel, as described herein, and certain other conditions. Certain legal matters, other than the validity of the Bonds and the exclusion from gross income for Federal income tax purposes of interest thereon, will be passed on for the Underwriter by its counsel, Hunton & Williams LLP, New York, New York, for the Letter of Credit Bank by its counsel, Winston & Strawn LLP and for the Company by its internal counsel. Delivery of the Bonds in book-entry-only form is expected on or about June 26, 2014, through the facilities of DTC in New York, New York, against payment therefor.

US Bancorp

Dated: June 19, 2014

CONTENTS OF OFFICIAL STATEMENT

No person has been authorized to give any information or to make any representations other than those contained in this Official Statement in connection with the offer made hereby and, if given or made, such information or representations must not be relied upon as having been authorized by the Issuer, the Company, the Letter of Credit Bank or the Underwriter. Neither the delivery of this Official Statement nor any sale hereunder shall under any circumstances create any implication that there has been no change in the affairs of the Issuer, the Letter of Credit Bank or the Company since the date hereof. This Official Statement does not constitute an offer or solicitation in any jurisdiction in which such offer or solicitation is not authorized, or in which the person making such offer or solicitation is not qualified to do so or to any person to whom it is unlawful to make such offer or solicitation. The Issuer neither has nor assumes any responsibility as to the accuracy or completeness of the information in this Official Statement, all of which has been furnished by others, other than information under *THE ISSUER*.

The Underwriter has provided the following sentence for inclusion in this Official Statement. The Underwriter has reviewed the information in this Official Statement in accordance with, and as a part of, its responsibilities to investors under the federal securities laws as applied to the facts and circumstances of this transaction, but the Underwriter does not guarantee the accuracy or completeness of such information.

CERTAIN PERSONS PARTICIPATING IN THIS OFFERING MAY ENGAGE IN TRANSACTIONS THAT STABILIZE, MAINTAIN OR OTHERWISE AFFECT THE PRICE

OF THE BONDS, INCLUDING BY ENTERING STABILIZING BIDS. FOR A DESCRIPTION OF THESE ACTIVITIES, SEE *UNDERWRITING* HEREIN.

IN MAKING AN INVESTMENT DECISION, INVESTORS MUST RELY ON THEIR OWN EXAMINATION OF THE ISSUER, THE COMPANY AND THE TERMS OF THE OFFERING, INCLUDING THE MERITS AND RISKS INVOLVED. THESE SECURITIES HAVE NOT BEEN RECOMMENDED BY ANY FEDERAL OR STATE SECURITIES COMMISSION OR REGULATORY AUTHORITY. FURTHERMORE, THE FOREGOING AUTHORITIES HAVE NOT CONFIRMED THE ACCURACY OR DETERMINED THE ADEQUACY OF THIS OFFICIAL STATEMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

$65,000,000
West Virginia Economic Development Authority
Solid Waste Disposal Facilities Revenue Refunding Bonds
(Kentucky Power Company - Mitchell Project),
Series 2014A

INTRODUCTORY STATEMENT

This Official Statement, including the Appendices hereto, is provided to furnish certain information in connection with the issuance by the West Virginia Economic Development Authority, a public corporation and governmental instrumentality of the State of West Virginia ("Issuer") of its Solid Waste Disposal Facilities Revenue Refunding Bonds (Kentucky Power Company - Mitchell Project), Series 2014A, in the aggregate principal amount of $65,000,000 (the "Bonds"). The Issuer neither has nor assumes any responsibility as to the accuracy or completeness of the information in this Official Statement, all of which has been furnished by others, other than the information pertaining to the Issuer under *THE ISSUER*.

The Bonds will be issued under and pursuant to a resolution of the Issuer adopted on March 20, 2014 ("Resolution") and an Indenture of Trust, dated as of June 15, 2014 ("Indenture"), between the Issuer and The Bank of New York Mellon Trust Company, N.A., as trustee (in such capacity, the "Trustee"). Capitalized terms used herein and not otherwise defined shall have the meanings given to them in the Indenture.

Pursuant to a Loan Agreement, dated as of June 15, 2014 ("Agreement"), between the Issuer and Kentucky Power Company ("Company"), the Issuer will loan to the Company the proceeds of the Bonds to be used to provide funds to refund or to pay at redemption the Issuer's Solid Waste Disposal Facilities Revenue Bonds (Ohio Power Company – Mitchell Project) Series 2008A (the "Refunded Bonds"). The Refunded Bonds were issued to redeem bonds that were issued by the Issuer for the purpose of providing a portion of the funds for the acquisition, construction and improvement of solid waste disposal facilities (the "Project"), or portions thereof, designed for the disposal of solid wastes at the Mitchell Generating Station located near Moundsville, West Virginia (the "Plant").

In order to evidence the loan from the Issuer (the "Loan") and to provide for its repayment, the Company will issue a nonnegotiable promissory note (the "Note") pursuant to the Agreement. Payments required under the Note will be sufficient, together with any other funds on deposit in the Bond Fund (hereinafter described) under the Indenture, to pay the principal of and premium, if any, and interest on the Bonds and to make or provide for payments to the paying agent for the Bonds ("Paying Agent"), initially The Bank of New York Mellon Trust Company, N.A., equal to 100% of the principal amount of the Bonds plus accrued interest, if any, upon tender thereof ("Purchase Price"). The Bonds will not otherwise be secured by a mortgage on, or security interest in, any of the Project or any other property of the Company.

The Bonds will initially bear interest at a Weekly Rate until converted to another permitted interest rate mode as described herein. While accruing interest at the Daily or Weekly Rates, the Bonds are subject to optional and mandatory tender, as described herein. Bonds converted to a different interest rate mode will be subject to mandatory tender upon conversion.

When a Daily Rate or Weekly Rate is in effect for the Bonds, holders of the Bonds will have the option to tender their Bonds for purchase as described herein. The Daily Rate or Weekly Rate for an interest period for the Bonds will be determined by the Remarketing Agent as set forth in the Indenture.

While the Bonds bear interest at a Daily Rate or a Weekly Rate they will be issued in denominations of $100,000 and any larger denominations constituting an integral multiple of $5,000. The Bonds will be held by The Depository Trust Company ("DTC"), or its nominee, as securities depository with respect to the Bonds. See *THE BONDS – Book-Entry Only System*.

Concurrently with the issuance of the Bonds, the Company will cause to be delivered to the Trustee an irrevocable direct pay letter of credit (the "Letter of Credit") issued by the Letter of Credit Bank, in the initial aggregate stated amount of $65,747,945. Under the Letter of Credit, the Trustee will be permitted to draw up to (a) an amount sufficient to pay (i) the principal of the Bonds when due at maturity, redemption or acceleration and (ii) the portion of the Purchase Price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the principal amount of such Bonds, plus (b) an amount equal to 35 days' interest on the Bonds at a maximum rate of 12% per annum to pay (i) interest on the Bonds when due and (ii) the portion of the Purchase Price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the accrued interest on such Bonds. The expiration date of the Letter of Credit is June 26, 2017 unless earlier terminated or extended as described under *The Letter of Credit and Reimbursement Agreement—the Letter of Credit*. The Letter of Credit may be replaced by an Alternate Letter of Credit (as defined herein) prior to its expiration date as described under *The Letter of Credit and Reimbursement Agreement—Replacement of Letter of Credit* herein. If the Letter of Credit expires, is replaced by an Alternate Letter of Credit or is surrendered, the Bonds will be subject to mandatory tender for purchase, as described under *The Bonds — Mandatory Tender for Purchase* herein. The Letter of Credit will be issued pursuant to the Reimbursement Agreement dated as of June 26, 2014 (the "Reimbursement Agreement"), between the Letter of Credit Bank and the Company.

The Bonds are special obligations of the Issuer, and are to be paid solely from, and will be secured by a pledge of, payments to be made to the Issuer under the terms of the Agreement and funds drawn under the Letter of Credit. See *THE BONDS – Security for the Bonds.*

Brief descriptions of the Issuer, the Company, the Letter of Credit Bank and the Project and certain provisions of the Bonds, the Agreement, the Indenture, the Letter of Credit and the Reimbursement Agreement are included in this Official Statement. Certain information with respect to the Company is set forth in Appendix A hereto. Certain information with respect to the Letter of Credit Bank is set forth in Appendix B hereto. Appendix C to this Official Statement sets forth the form of opinion Bond Counsel proposes to deliver relating to the Bonds. The descriptions herein of provisions of the Agreement, the Indenture, the Letter of Credit and the Reimbursement Agreement are qualified in their entirety by reference to such documents, and the description herein of provisions of the Bonds is qualified in its entirety by reference to the form thereof included in the Indenture and the information with respect thereto included in the aforesaid documents. All such descriptions are further qualified in their entirety by reference to laws and principles of equity relating to or affecting generally the enforcement of creditor's rights. Copies of such documents may be obtained from the office of the Company and are available for inspection at the office of the Trustee. Words and terms not defined herein shall have the meanings set forth in the respective documents.

THE ISSUER

The West Virginia Economic Development Authority, empowered and authorized pursuant to Chapter 31, Article 15, Section 1, et. seq. of the Code of West Virginia, 1931, as amended (the "Act"), is a body corporate and politic, constituting a public corporation and government instrumentality of the State of West Virginia, with the power to borrow money and issue its bonds and other debt instruments for any of its purposes, and to finance making loans to finance any project to private corporations or to refund bonds issued for such purposes. Such projects include solid waste disposal facilities. The Issuer has no taxing power.

THE BONDS SHALL NOT CONSTITUTE A DEBT OR A PLEDGE OF THE FAITH AND CREDIT OR TAXING POWER OF THE STATE OF WEST VIRGINIA OR OF ANY COUNTY, MUNICIPALITY OR ANY OTHER POLITICAL SUBDIVISION OF THE STATE OF WEST VIRGINIA, AND THE HOLDERS AND OWNERS THEREOF SHALL HAVE NO RIGHT TO HAVE TAXES LEVIED BY THE LEGISLATURE OF THE STATE OF WEST VIRGINIA OR THE TAXING AUTHORITY OF ANY COUNTY, MUNICIPALITY OR ANY OTHER POLITICAL SUBDIVISION OF THE STATE OF WEST VIRGINIA FOR THE PAYMENT OF THE PRINCIPAL OF, INTEREST ON OR PURCHASE PRICE OF THE BONDS, BUT SHALL BE PAYABLE SOLELY FROM REVENUES AND FUNDS PLEDGED FOR ITS PAYMENT AS AUTHORIZED BY THE ACT.

THE PROJECT

The Project consists of various systems which are designed for the disposal of solid wastes resulting from the operation of the Plant. The solid waste disposal facilities are comprised of the portion of the flue gas desulfurization system (the "FGD System") constructed with respect to the two 800 megawatt units at the Plant that relates to the disposal of solid waste generated as part of the FGD System.

USE OF PROCEEDS

The Issuer will cause the proceeds received upon sale of the Bonds to be deposited into the Refunding Fund created under the Indenture to be used to refund the Refunded Bonds within 90 days of the issuance of the Bonds. See *THE INDENTURE– Refunding Fund*.

THE BONDS

This Official Statement does not provide any information regarding the Bonds after the date, if any, on which the Bonds convert to bear interest, as permitted by the Indenture, at interest rates other than a Daily Rate or Weekly Rate. The Bonds are subject to

mandatory tender in the event of any such conversion. See *THE BONDS -- Mandatory Tender for Purchase* below.

The Bonds are special obligations of the Issuer and will be payable solely from the revenues and receipts arising out of or in connection with the Loan Agreement and funds drawn under the Letter of Credit.

General

The Bonds will be dated as of the date of the initial authentication and delivery thereof and will mature on April 1, 2036. The Bonds initially will bear interest at a Weekly Rate commencing on the date of the issuance of the Bonds, subject to conversion to other interest rate modes as described herein.

Beneficial interests in the Bonds will initially be issued pursuant to a Book-Entry Only System ("Book-Entry Only System") maintained by The Depository Trust Company, New York, New York ("DTC"), as described below under the caption *Book-Entry Only System*. Under the Indenture, the Issuer may appoint a successor securities depository to DTC. (DTC, together with any such successor securities depository, is hereinafter referred to as the "Securities Depository"). The following information is subject in its entirety to the provisions described below under the caption *Book-Entry Only System* while the Bonds are in the Book-Entry Only System.

Upon surrender of the Bonds, principal of and premium, if any, on the Bonds are payable at maturity or upon redemption at the principal office of the Trustee. As long as the Bonds are held by DTC, interest will be paid to DTC on each payment date. If the book-entry system is discontinued, interest on the Bonds will be payable by check or draft mailed by the Trustee to the registered owners.

Form and Denomination of Bonds; Payments on the Bonds

<u>General</u>

While the Bonds bear interest at a Daily Rate or a Weekly Rate they will be issued only as fully registered bonds, without coupons, in denominations of $100,000 and any larger denomination constituting an integral multiple of $5,000 (an "Authorized Denomination"). The Bonds will be registered in the name of Cede & Co., as registered owner and nominee of DTC. DTC acts as securities depository for the Bonds and individual purchases of Bonds may be made in book-entry form only. So long as the Bonds are in book-entry only form, purchasers of Bonds will not receive certificates representing their interest in the Bonds purchased. So long as Cede & Co. is the registered owner of such Bonds, as nominee of DTC, references herein to the Bondholders or registered owners or holder shall mean Cede & Co., and shall not mean the Beneficial Owners (as defined below) of the Bonds.

So long as Cede & Co. is the registered owner of the Bonds, principal of and interest on the Bonds are payable to Cede & Co., as nominee for DTC, which will, in turn, remit such amounts to the DTC Participants (as defined below) for subsequent disbursement to the Beneficial Owners. See – *Book-Entry Only System* below.

The Bank of New York Mellon Trust Company, N.A. has been appointed as Trustee and Paying Agent under the Indenture. The designated office of the Trustee and Paying Agent is located at 6525 W. Campus Oval, 2nd Floor, New Albany, Ohio 43054.

The Trustee will not be required to make any transfer or exchange of any Bond during the ten days prior to the mailing of a notice of Bonds selected for redemption or, with respect to a Bond, after such Bond or any portion thereof has been selected for redemption. Registration of transfers and exchanges shall be made without charge to the Bondholders, except that any required taxes or other governmental charges shall be paid by the Bondholder requesting registration of transfer or exchange.

Interest

Interest on the Bonds will be payable as described below. Interest on the Bonds initially will be payable at a Weekly Rate on the first Business Day of each month, commencing July 1, 2014. The interest rate determination method for the Bonds may be changed by the Company as described under *Change in Interest Rate Determination Method* below. See *Summary* below for a table summarizing certain provisions of the Bonds.

"*Business Day*" means any day other than (i) a Saturday or Sunday, (ii) a day on which commercial banks in New York, New York or the city in which the designated corporate trust office of the Trustee or the principal office of the Remarketing Agent or payment office of the Letter of Credit Bank is located, are required or authorized by law to close, or (iii) a day on which the New York Stock Exchange is closed.

Interest will accrue on the unpaid portion of the principal of the Bonds from the last date to which interest was paid, or if no interest has been paid, from the date of the original issuance of the Bonds until the entire principal amount of the Bonds is paid. When interest is payable at a Daily or Weekly Rate, interest will be computed on the basis of the actual number of days elapsed over a year of 365 days (366 days in leap years).

Daily Rate. When interest on the Bonds is payable at a Daily Rate, the Remarketing Agent will set a Daily Rate on or before 10:00 A.M., New York City time, on each Business Day for that Business Day. Each Daily Rate will be the minimum rate necessary (as determined by the Remarketing Agent based on the examination of tax-exempt obligations comparable to the Bonds known by the Remarketing Agent to have been priced or traded under then-prevailing market conditions) for the Remarketing Agent to sell the Bonds on the day the Daily Rate is set at their principal amount (without regard to accrued interest). The Daily Rate for any non-Business Day will be the rate for the last day for which a rate was set.

Weekly Rate. When interest on the Bonds is payable at a Weekly Rate, the Remarketing Agent will set a Weekly Rate on or before 5:00 P.M., New York City time, on the last Business Day before the commencement of a period during which the Bonds are to bear interest at a Weekly Rate and on each Wednesday thereafter so long as interest on the Bonds is to be payable at a Weekly Rate or, if any Wednesday is not a Business Day, on the next preceding Business Day. Each Weekly Rate will be the minimum rate necessary (as determined by the Remarketing Agent based on the examination of tax-exempt obligations comparable to the Bonds known by the Remarketing Agent to have been priced or traded under then-prevailing market conditions) for the Remarketing Agent to sell the Bonds on the date the Weekly Rate is set at their principal amount (without regard to accrued interest). Each Weekly Rate shall apply to (i) the period beginning on the Thursday after the Weekly Rate is set and ending on the following Wednesday or, if earlier, ending on the day before the effective date of a new method of determining the interest rate on the Bonds or (ii) the period beginning on the effective date of the change to a Weekly Rate and ending on the next Wednesday.

Fallback Interest Period and Rate. If the appropriate Daily or Weekly Rate is not or cannot be determined for any reason, the method of determining interest on the Bonds will be payable at the Alternate Rate.

"Alternate Rate" means, as of any date, the rate equal to The Securities Industry and Financial Markets Association ("SIFMA") Municipal Swap Index of Municipal Market Data most recently available as of the date of determination or, if such index is no longer available, or if the rate is no longer published, a comparable index as described in the Indenture.

Calculation and Notice of Interest. The Remarketing Agent will provide the Trustee and the Company with notice in writing or by other written electronic means or by telephone promptly confirmed by facsimile transmission by 1:00 P.M., New York City time, (i) on the last Business Day of a month in which interest on the Bonds was payable at a Daily Rate, of the Daily Rate for each day in such month, (ii) on each day on which a Weekly Rate becomes effective, of the Weekly Rate and (iii) on any Business Day preceding any redemption or purchase date, any interest rate requested by the Trustee in order to enable it to calculate the accrued interest, if any, due on such redemption or purchase date. Using the rates supplied by such notice, the Trustee will calculate the interest payable on the Bonds. The Remarketing Agent will inform the Trustee and the Company orally at the oral request of either of them of any interest rate so set. The Trustee will confirm the effective interest rate in writing to any Bondholder who requests it.

The setting of the rates by the Remarketing Agent and the calculation of interest payable on the Bonds by the Trustee as provided in the Indenture will be conclusive and binding on the Issuer, the Company, the Trustee and the owners of the Bonds.

Change in Interest Rate Determination Method. The Company may change the method of determining the interest rate on all but not part of the Bonds, from time to time by notifying the Issuer, the Trustee, the Letter of Credit Bank and the Remarketing Agent. The Company's notice will specify (i) the effective date of the proposed change in interest rate determination method, (ii) the proposed interest rate determination method and (iii) a statement as to whether the Letter of Credit shall be terminated in connection with such change. The interest rate payable on the Bonds will be payable at the proposed rate on the effective date specified in the Company's notice, provided that: (i) the Company's notice complies with the provisions of the Indenture and the change to the proposed interest rate determination method complies with certain limitations set forth in the Indenture; and (ii) a Favorable Opinion of Tax Counsel required under the Indenture has been delivered with the notice (see *Cancellation of Change in Interest Rate Determination Method if Opinion of Tax Counsel is Not Confirmed* below). It is currently anticipated that, should any of the Bonds be converted to bear interest at any rate other than a Daily Rate or a Weekly Rate, a reoffering memorandum or reoffering circular will be distributed describing the Bonds while they bear interest at any such interest rate.

Notice of Change in Interest Rate Determination Method. The Trustee, upon receiving notice from the Company pursuant to the Indenture, is required to give at least 15 days written notice by first-class mail to the Bondholders before the effective date of a change in the interest rate determination method. Each notice will be effective when sent and will state: (i) that the interest rate determination method will change and what the new method will be; (ii) the proposed effective date of the new interest rate; and (iii) that the Bonds will be subject to mandatory tender on the effective date of the change and the information required to be included in a notice of tender pursuant to the Indenture. See *Mandatory Tender for Purchase-Notice of Tender* below.

Cancellation of Change in Interest Rate Determination Method if Opinion of Tax Counsel is Not Confirmed. No change will be made in the interest rate determination method at the direction of the Company as described under *Change in Interest Rate Determination Method* above if the Company shall fail to deliver the Favorable Opinion of Tax Counsel described under *Change in Interest Rate Determination Method* above. If notice of a change in the interest rate determination method has been mailed and, subsequently, a Favorable Opinion of Tax Counsel is rescinded, then the Trustee shall so notify the bondholders and the Bonds shall still be subject to a mandatory tender on the proposed date of change in the interest rate determination method and the Remarketing Agent shall remarket the Bonds pursuant to the terms of the Indenture.

Special Considerations Relating to the Bonds

The Remarketing Agent is Paid by the Company

The Remarketing Agent's responsibilities include determining the interest rate from time to time and remarketing Bonds that are optionally or mandatorily tendered by the owners thereof (subject, in each case, to the terms of the Remarketing Agreement (as defined herein)), all as further described in this Official Statement. The Remarketing Agent is appointed by the Company and is paid by the Company for its services. As a result, the interests of the Remarketing Agent may differ from those of existing holders and potential purchasers of Bonds.

The Remarketing Agent Routinely Purchases Bonds for its Own Account

The Remarketing Agent acts as remarketing agent for a variety of variable rate demand obligations and, in its sole discretion, routinely purchases such obligations for its own account in order to achieve a successful remarketing of the obligations (i.e., because there are otherwise not enough buyers to purchase the obligations) or for other reasons. The Remarketing Agent is permitted, but not obligated, to purchase tendered Bonds for its own account and, if it does so, it may cease doing so at any time without notice. The Remarketing Agent may also make a market in the Bonds by routinely purchasing and selling Bonds other than in connection with an optional or mandatory tender and remarketing. Such purchases and sales may be at or below par. However, the Remarketing Agent is not required to make a market in the Bonds. The Remarketing Agent may also sell any Bonds it has purchased to one or more affiliated investment vehicles for collective ownership or enter into derivative arrangements with affiliates or others in order to reduce its exposure to the Bonds. The purchase of Bonds by the Remarketing Agent may create the appearance that there is greater third party demand for the Bonds in the market than is actually the case. The practices described above also may result in fewer Bonds being tendered in a remarketing.

Bonds may be Offered at Different Prices on Any Date

Pursuant to the Indenture, the Remarketing Agent is required to determine the applicable rate of interest that, in its judgment, is the minimum rate necessary (as determined by the Remarketing Agent based on the examination of tax-exempt obligations comparable to the Bonds known by the Remarketing Agent to have been priced or traded under then-prevailing market conditions) for the Remarketing Agent to sell the Bonds on the day the rate is set at their principal amount (without regard to accrued interest). The interest rate will reflect, among other factors, the level of market demand for the Bonds (including whether the Remarketing Agent is willing to purchase Bonds for its own account). There may or may not be Bonds tendered and remarketed on a day that the rate on the Bonds is set, the Remarketing Agent may or may not be able to remarket any Bonds tendered for purchase on such date at par and the Remarketing Agent may sell Bonds at varying prices to different investors on such date or any other date. The Remarketing Agent is not obligated to advise purchasers in a remarketing if it does not have third party buyers for all of the Bonds at the remarketing price. In the event the Remarketing Agent owns any Bonds for its own account, it may, in its sole discretion in a secondary market transaction outside the tender process, offer such Bonds on any date, including the day that the rate on the Bonds are set, at a discount to par to some investors.

The Ability to Sell the Bonds other than through Tender Process May be Limited

The Remarketing Agent may buy and sell Bonds other than through the tender process. However, it is not obligated to do so and may cease doing so at any time without notice and may require holders that wish to tender their Bonds to do so through the Trustee with appropriate notice. Thus, investors who purchase the Bonds, whether in a remarketing or otherwise, should not assume that they will be able to sell their Bonds other than by tendering the Bonds in accordance with the tender process.

Under Certain Circumstances, the Remarketing Agent May Be Removed, Resign or Cease Remarketing the Bonds, Without a Successor Being Named

Under certain circumstances, the Remarketing Agent may be removed or have the ability to resign or cease its remarketing efforts, without a successor having been named, subject to the terms of the Remarketing Agreement and the Indenture.

Optional Tender

While the Bonds bear interest at a Daily Rate or a Weekly Rate, the holder of any Bond may elect to have its Bond (or any portion of its Bond equal to the lowest authorized denomination or whole multiples thereof) purchased by the Trustee at the Purchase Price.

Daily Rate Tender. When interest on a Bond is payable at a Daily Rate and a book-entry system is in effect, a Beneficial Owner of such Bond (through its Direct Participant (as defined in *Book-Entry Only System* below) in the Securities Depository) may tender its interest in a Bond (or portion of Bond) by delivering an irrevocable written notice by telecopy, facsimile transmission or e-mail transmission to the Trustee and an irrevocable notice to the Remarketing Agent by telephone, telegraph or facsimile transmission, in each case prior to 11:00 A.M., New York City time, on a Business Day, stating the principal amount of the Bond (or portion of Bond) being tendered, payment instructions for the Purchase Price and the Business Day (which may be the date the notice is delivered) the Bond (or portion of Bond) is to be purchased. The Beneficial Owner will effect delivery of such Bond by causing such Direct Participant to transfer its interest in the Bond equal to such Beneficial Owner's interest on the records of the Securities Depository to the participant account of the Trustee with the Securities Depository. Any notice received by the Trustee after 11:00 A.M., New York City time, will be deemed to have been given on the next Business Day.

When interest on a Bond is payable at a Daily Rate and a book-entry system is not in effect, a holder of a Bond may tender the Bond (or portion of Bond) by delivering (i) the notices described above (which must include the certificate number of the Bond) and (ii) the Bond, to the Trustee by 1:00 P.M., New York City time, on the date of purchase.

Weekly Rate Tender. When interest on a Bond is payable at a Weekly Rate and a book-entry system is in effect, a Beneficial Owner of such Bond (through its Direct Participant in the Securities Depository) may tender its interest in a Bond (or portion of Bond) by delivering an irrevocable written notice by telecopy, facsimile transmission or e-mail transmission to the Trustee and an irrevocable notice to the Remarketing Agent by telephone, telegraph or facsimile transmission, in each case prior to 5:00 P.M., New York City time, on a Business Day stating the principal amount of the Bond (or portion of Bond) being tendered, payment instructions for the Purchase Price and the date, which must be a Business Day at least seven days after the notice is delivered, on which the Bond (or portion of Bond) is to be purchased. The Beneficial Owner shall effect delivery of such Bond by causing such Direct Participant to transfer its interest in the Bond equal to such Beneficial Owner's interest on the records of the Securities Depository to the participant account of the Trustee or its agent with the Securities Depository.

When interest on a Bond is payable at a Weekly Rate and a book-entry system is not in effect, a holder of a Bond may tender the Bond (or portion of Bond) by delivering (i) the notices as described above (which must include the certificate number of the Bond) and (ii) the Bond, to the Trustee by 1:00 P.M., New York City time, on the date of purchase.

Payment of Purchase Price. Payment of the Purchase Price of Bonds to be purchased upon optional tender as described above will be made by the Trustee in immediately available funds by 4:00 P.M., New York City time, on the date of purchase. No purchase of Bonds by the

Trustee will be deemed to be a payment or redemption of the Bonds or of any portion thereof and such purchase will not operate to extinguish or discharge the indebtedness evidenced by such Bonds. So long as the Letter of Credit is in effect, all payments of Purchase Price for the Bonds shall be made in accordance with the Indenture. See *Summary* below.

Provisions Applicable to All Tenders. Bonds for which the owners have given notice of tender for purchase but which are not delivered on the tender date shall be deemed tendered. Bonds tendered for purchase on a date after a call for redemption has been given but before the redemption date will be purchased pursuant to the tender.

Notice in respect of tenders and Bonds tendered must be delivered as follows:

Trustee	Remarketing Agent
The Bank of New York Mellon Trust Company, N.A. 6525 W. Campus Oval, 2nd Floor New Albany, Ohio 43054 Attention: Corporate Trust Administration Telephone: (614) 775-5280 Telecopier: (614) 775-5636	U.S. Bancorp Municipal Securities Group 461 Fifth Avenue New York, New York 10017 Attn: Short-Term Trading Telephone: 827-497-0032

Irrevocability

Each notice of tender constitutes an irrevocable tender for purchase of the Bond (or portion thereof) to which the notice relates on the purchase date at a price equal to 100% of the principal amount of such Bond (or portion thereof) plus any interest thereon accrued and unpaid as of the purchase date. The determination of the Trustee as to whether a notice of tender has been properly sent will be conclusive and binding upon the Bondholders.

The Trustee may refuse to accept delivery of any Bond for which a proper instrument of transfer has not been provided. If any owner of a Bond who gave notice of optional tender or which is subject to mandatory tender fails to deliver its Bond to the Trustee at the place and on the applicable date and time specified, or fails to deliver its Bond properly endorsed, and moneys for the payment of such Bond are on deposit with the Trustee, its Bond shall constitute an undelivered Bond and interest shall cease to accrue on its Bonds as of the tender date and such owner shall have no right under the Indenture other than the right to receive payment of the Purchase Price thereof.

Remarketing and Purchase

Except to the extent the Company directs the Remarketing Agent not to remarket Bonds and except as otherwise provided in the Indenture, the Remarketing Agent for the Bonds will offer for sale and use reasonable efforts to sell all Bonds tendered for purchase (as described below) at a price equal to 100% of the principal amount thereof plus accrued interest, if any, to the purchase date. The Trustee will pay the Purchase Price of the Bonds tendered for purchase first from the proceeds of the remarketing of such Bonds to persons other than the Company, the affiliates of the Company and the Issuer and, if such proceeds are insufficient, second from the proceeds of a draw upon the Letter of Credit and, third, from money provided by the Company or otherwise available. See *THE REMARKETING AGREEMENT* below.

Redemption of Bonds

The Bonds are subject to redemption as described below:

Extraordinary Optional Redemption. The Bonds are subject to redemption by the Issuer in whole or in part on any date if the Company, upon the occurrence of any of the following events, exercises its option to direct that redemption from moneys available therefor at a redemption price of 100% of the principal amount redeemed, plus accrued and unpaid interest to the redemption date:

(a) The Project or the Plant (each as defined in the Agreement) shall have been damaged or destroyed to such an extent that the Company deems it not practical or desirable to rebuild, repair or restore the Project or Plant, as the case may be.

(b) Title to, or the temporary use of, all or a significant part of the Project or the Plant shall have been taken under the exercise of the power of eminent domain so as to render the Project unsatisfactory to the Company for its intended purpose.

(c) As a result of any changes in the Constitution of the State of West Virginia, the Constitution of the United States of America or any state or federal laws or as a result of legislative or administrative action (whether state or federal) or by final decree, judgment or order of any court or administrative body (whether state or federal) entered after any contest thereof by the Issuer or the Company in good faith, the Agreement shall have become void or unenforceable or impossible of performance in accordance with the intent and purpose of the parties as described therein.

(d) Unreasonable burdens or excessive liabilities shall have been imposed upon the Issuer or the Company with respect to the Project or the Plant or the operation thereof, including, without limitation, the imposition of federal, state or other ad valorem, property, income or other taxes not being imposed on the date of the Agreement.

(e) Changes in the economic availability of raw materials, operating supplies, energy sources or supplies or facilities (including, but not limited to, facilities in connection with the disposal of industrial wastes) necessary for the operation of the Project or the Plant occur or technological or other changes occur which in the Company's reasonable judgment render the Project or the Plant uneconomic or obsolete.

(f) Any court or administrative body shall enter a judgment, order or decree, or shall take administrative action, requiring the Company to cease all or any substantial part of its operations served by the Project or the Plant to such extent that the Company is or will be prevented from carrying on its normal operations at the Project or the Plant for a period of six consecutive months.

(g) The termination by the Company of operations at the Plant.

Extraordinary Mandatory Redemption. The Bonds are subject to mandatory redemption at any time in whole, or in part if such partial redemption will preserve the exemption from federal income taxation of interest on the remaining outstanding Bonds, at a redemption price equal to the principal amount thereof together with unpaid interest accrued to the date fixed for redemption, and without premium, if (a) a final decree or judgment of any federal court, in which the Company participates to the extent it deems sufficient, or (b) a final action by the Internal Revenue Service, in proceedings in which the Company participates to the extent it deems sufficient, determines that the interest paid or payable on Bonds to a person, other than, as provided in Section 147(a) of the Code, a "substantial user" of the Project or a "related person", is or was includable in the gross income of the owner thereof for federal income tax purposes under the Code, as a result of the failure by the Company to observe or perform any covenant, condition or agreement on its part to be observed or performed under the Agreement or the inaccuracy of any representation by the Company under the Agreement or receipt by the Company of an Opinion of Tax Counsel to such effect obtained by the Company and rendered at the request of the Company; provided, however, that no decree or judgment by any court or action by the Internal Revenue Service shall be considered final unless the Bondholder or Beneficial Owner involved in such proceeding or action (i) gives the Company and the Trustee prompt written notice of the commencement thereof and (ii) if the Company agrees to pay all expenses in connection therewith and to indemnify such Bondholder or Beneficial Owner against all liabilities in connection therewith, offers the Company the opportunity to control the defense thereof. Any such redemption shall be made on a date determined by the Trustee not more than 180 days after the date of such final decree, judgment or action. The Trustee shall give the Issuer and the Company not less than 45 days written notice of such date.

Optional Redemption. When interest on the Bonds is payable at a Daily or Weekly Rate, the Bonds may be redeemed in whole or in part at the option of the Company, on any Business Day.

Notice of Redemption. Whenever Bonds are to be redeemed, the Trustee shall give notice of redemption by mailing such notice to the registered owner of each Bond to be redeemed, at least 30 days prior to the redemption date, as provided in the Indenture.

During the period that DTC or the DTC nominee is the registered holder of the Bonds, the Trustee will not be responsible for mailing notices of redemption, or other notices described herein, to the Beneficial Owners of the Bonds. See - *Book-Entry Only System*.

Mandatory Tender for Purchase

The Bonds are subject to mandatory tender for purchase under certain circumstances. By acceptance of each Bond, the holder agrees to sell and surrender its Bond, properly endorsed, under the conditions described below. All purchases will be made in funds immediately available on the purchase date and will be at the Purchase Price. Bonds tendered for purchase on a date after a call for redemption but before the redemption date will be purchased pursuant to the tender. No purchase of Bonds shall be deemed to be a payment or redemption of the Bonds or of any portion thereof and such purchase will not operate to extinguish or discharge the indebtedness evidenced by such Bonds.

Mandatory Tender Upon a Change in the Method of Determining the Interest Rate on the Bonds. On the effective date of the change in the method of determining the interest rate on the Bonds, the Bonds will be purchased on the effective date of such change at the Purchase Price.

At least 15 days before each mandatory tender occasioned by such change, the Trustee will mail a notice of tender by first-class mail to each Bondholder at the holder's registered address. Each notice of tender will identify the Bonds to be purchased and will state, among other things, (i) the purchase date; (ii) the Purchase Price; (iii) that the Bonds to be tendered must be surrendered to collect the Purchase Price; (iv) the address at which the Bonds must be surrendered; and (v) that interest on the Bonds to be tendered ceases to accrue to such holder on the purchase date.

Mandatory Tender Upon Substitution of Alternate Letter of Credit. The Bonds shall be subject to mandatory tender at the Purchase Price on the date on which an Alternate Letter of Credit is to be substituted for the Letter of Credit (the "Substitution Date"). Bonds purchased pursuant to this provision shall be delivered by the holders at or before 12:00 noon, New York City time, on such Substitution Date, and, subject to the Indenture, payment of the Purchase Price of such Bonds shall be made by wire transfer in immediately available funds by the Trustee on such Substitution Date. The Trustee shall give notice of such mandatory tender by mail to the holders of the Bonds no less than twenty (20) days prior to the Substitution Date. The notice shall state (i) that the Bonds are subject to mandatory tender, (ii) the Substitution Date; (iii) the Purchase Price; (iv) that Bonds must be surrendered to collect the Purchase Price; (v) the address at which the Bonds must be surrendered; and (vi) that interest on Bonds subject to mandatory tender will cease to accrue to such holder from and after the Substitution Date and such holder will be entitled only to the Purchase Price on the Substitution Date. The failure to mail such notice with respect to any Bond shall not affect the validity of the mandatory tender of any other Bond with respect to which notice was so mailed. Any notice mailed will be conclusively presumed to have been given, whether or not actually received by any holder.

"Alternate Letter of Credit" means, with respect to the Bonds, a letter of credit or other security or liquidity device issued in accordance with the requirements of the Indenture which will have a term of not less than one year and will have substantially the same material terms as the Letter of Credit; provided that such letter of credit or other security or liquidity device may (and shall if the Bonds shall provide for redemption premium while it is in effect) provide for coverage of premium payable upon redemption of the Bonds.

Mandatory Tender Due to an Event of Default Under Reimbursement Agreement. Whenever the Letter of Credit is in effect, the Bonds will be subject to mandatory tender if the Trustee receives a written notice from the Letter of Credit Bank that an event of default, as defined in the Reimbursement Agreement, has occurred and is continuing, and the Letter of Credit Bank directs the Trustee to effect such mandatory tender. Such Bonds subject to mandatory tender will be purchased at the Purchase Price on the default tender date specified by the Letter of Credit Bank in such written notice (the "Default Tender Date"). Such Default

Tender Date shall be a Business Day not more than nine (9) nor less than five (5) days after the day such notice is received. The Trustee shall immediately notify the paying agent of receipt of such notice and of the Default Tender Date. Bonds purchased pursuant to this provision will be delivered by the holders (with all necessary endorsements) to the designated corporate trust office of the Trustee, at or before 12:00 noon, New York City time, on the Default Tender Date, and, subject to the Indenture, payment of the Purchase Price shall be made by wire transfer in immediately available funds by the Trustee on the Default Tender Date; provided, however, that payment of the Purchase Price shall be made pursuant to this provision only if the Bond is so delivered to the Trustee.

The Trustee will give notice to the Issuer, the Remarketing Agent, the Company and the Letter of Credit Bank (the "Notice Parties") and all holders prior to the close of business on the Business Day after receipt of the notice described in the preceding paragraph stating (i) that the Bonds are subject to mandatory tender; (ii) the Default Tender Date; (iii) the Purchase Price; (iv) that Bonds must be surrendered to collect the Purchase Price; (v) the address at which the Bonds must be surrendered; (vi) that interest on such Bonds will cease to accrue to such holder from and after the Default Tender Date and such holder will be entitled only to the Purchase Price on the Default Tender Date; and (vii) if the Bonds are then rated by Moody's Investor Service, Inc. ("Moody's"), Standard & Poor's, a division of The McGraw-Hill Companies ("Standard & Poor's") or Fitch, Inc. ("Fitch"), that such rating or ratings will terminate on the Default Tender Date. The failure to mail such notice with respect to any Bond will not affect the validity of the mandatory tender of any other Bond with respect to which notice was so mailed. Any notice mailed will be conclusively presumed to have been given, whether or not actually received by a holder.

Mandatory Tender Upon Expiration or Termination of Letter of Credit. If (i) the Letter of Credit is scheduled to expire on the Expiration Date (as defined below) and by the Renewal Date (as defined below) no extension of such Letter of Credit or Alternate Letter of Credit has been delivered to the Trustee or (ii) on or before the Renewal Date, the Company has delivered notice in accordance with the Reimbursement Agreement, stating that the Letter of Credit will be terminated with respect to all the Bonds on the Expiration Date, then the Bonds shall be subject to mandatory tender on the date five Business Days prior to the Expiration Date (the "Expiration Tender Date") at the Purchase Price. Bonds purchased pursuant to this provision will be delivered by the holders at or before 12:00 noon, New York City time, on the Expiration Tender Date, and subject to the Indenture, payment of the Purchase Price shall be made by wire transfer in immediately available funds by the Trustee on such Expiration Tender Date; provided, however, that payment of the Purchase Price will be made pursuant to this provision only if the Bond is so delivered to the Trustee.

The Trustee will give notice to all holders and the Notice Parties no less than twenty (20) days prior to the Expiration Tender Date. The notice will state (i) that the Bonds are subject to mandatory tender; (ii) the Expiration Tender Date; (iii) the Purchase Price; (iv) that Bonds must be surrendered to collect the Purchase Price; (v) the address at which the Bonds must be surrendered; (vi) that the Letter of Credit will terminate on the date specified in such notice; (vii) that interest on such Bonds will cease to accrue to such holder from and after the Expiration Tender Date and such holder will be entitled only to the Purchase Price on the Expiration Tender

Date; and (viii) if the Bonds are then rated by Moody's, Standard & Poor's or Fitch, that such rating or ratings will terminate on the Expiration Tender Date. The failure to mail such notice with respect to any Bond shall not affect the validity of the mandatory tender of any other Bond with respect to which notice was so mailed. Any notice mailed will be conclusively presumed to have been given, whether or not actually received by a holder.

"Expiration Date" means the stated expiration date of the Letter of Credit, or such stated expiration date as it may be extended from time to time as provided in the Letter of Credit, or any earlier date on which the Letter of Credit shall expire or be terminated or cancelled.

"Renewal Date" means the thirty-fifth (35th) day prior to the Expiration Date.

Notice of Tender. Failure to give any required notice of tender as to any particular Bonds or any defect therein will not affect the validity of the tender of any Bonds in respect of which no such failure or defect occurs. Any notice mailed as described above shall be effective when sent and will be conclusively presumed to have been given whether or not actually received by the addressee.

Effect of Notice of Tender. When notice is required and given, and when Bonds are to be tendered without notice, Bonds tendered become due and payable on the purchase date; in such case when funds are deposited with the Trustee sufficient for purchase, interest on the Bonds to be purchased ceases to accrue as of the date of purchase.

Summary

Certain provisions of the Bonds and the Indenture (other than when the Bonds bear interest at a rate other than a Daily Rate or Weekly Rate) are summarized in the following table:

	DAILY RATE	WEEKLY RATE
OPTIONAL TENDER; NOTICE	On any Business Day; notice no later than 11:00 A.M., New York City time, same Business Day	On any Business Day; notice no later than 5:00 P.M., New York City time, seven days in advance
INTEREST PERIODS	Each day	Thursday through Wednesday
INTEREST RATE DETERMINED	Each Business Day by 10:00 A.M., New York City time	Each Wednesday (or next preceding Business Day)
INTEREST ACCRUAL PERIOD	Interest Payment Date to Interest Payment Date	Interest Payment Date to Interest Payment Date
INTEREST PAYMENT DATE	First Business Day of next month	First Business Day of next month

	DAILY RATE	WEEKLY RATE
RECORD DATE	Business Day before Interest Payment Date	Business Day before Interest Payment Date
OPTIONAL REDEMPTION BY COMPANY	On any Business Day	On any Business Day
MANDATORY TENDER	(i) On effective date of change in interest rate determination method, (ii) substitution of Alternate Letter of Credit, (iii) event of default under Reimbursement Agreement, and (iv) expiration or termination of Letter of Credit	(i) On effective date of change in interest rate determination method, (ii) substitution of Alternate Letter of Credit, (iii) event of default under Reimbursement Agreement, and (iv) expiration or termination of Letter of Credit

Book-Entry Only System

DTC, New York, New York will act as securities depository for the Bonds. The Bonds will be issued as fully-registered bonds registered in the name of Cede & Co. (DTC's partnership nominee) or such other name as may be requested by an authorized representative of DTC. One fully-registered Bond certificate will be issued for the Bonds, representing in the aggregate the total principal amount of the Bonds, and will be deposited with the Trustee on behalf of DTC.

DTC is a limited-purpose trust company organized under the New York Banking Law, a "banking organization" within the meaning of the New York Banking Law, a member of the Federal Reserve System, a "clearing corporation" within the meaning of the New York Uniform Commercial Code, and a "clearing agency" registered pursuant to the provisions of Section 17A of the Securities Exchange Act of 1934, as amended (the "1934 Act"). DTC holds and provides asset servicing for over 3.5 million issues of U.S. and non-U.S. equity issues, corporate and municipal debt issues and money market instruments (from over 100 countries) that DTC's participants ("Direct Participants") deposit with DTC. DTC also facilitates the post-trade settlement among Direct Participants of sales and other securities transactions in deposited securities, through electronic computerized book-entry transfers and pledges between Direct Participants' accounts. This eliminates the need for physical movement of securities. Direct Participants include both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, clearing corporations, and certain other organizations. DTC is a wholly-owned subsidiary of The Depository Trust & Clearing Corporation ("DTCC"). DTCC is the holding company for DTC, National Securities Clearing Corporation and Fixed Income Clearing Corporation, all of which are registered clearing agencies. DTCC is owned by the users of its regulated subsidiaries. Access to the DTC system is also available to others such as both U.S. and non-U.S. securities brokers and dealers, banks, trust companies, and clearing corporations that clear through or maintain a custodial relationship with a Direct Participant, either directly or indirectly (the "Indirect Participants"). The DTC rules applicable to its Participants are on file with the Securities and Exchange Commission ("SEC"). More information about DTC can be found at www.dtcc.com (it being understood that information available at this website is not incorporated herein by reference).

Purchases of Bonds under the DTC system must be made by or through Direct Participants, who will receive a credit for the Bonds on DTC's records. The ownership interest of each actual purchaser of each Bond (the "Beneficial Owner") is in turn to be recorded on the Direct and Indirect Participants' records. Beneficial Owners will not receive written confirmation from DTC of their purchase, but Beneficial Owners are expected to receive written confirmation providing details of the transaction, as well as periodic statements of their holdings, from the Direct or Indirect Participant through which the Beneficial Owner entered into the transaction. Transfers of ownership interests in the Bonds are to be accomplished by entries made on the books of Direct and Indirect Participants acting on behalf of Beneficial Owners. Beneficial Owners will not receive certificates representing their ownership interests in Bonds, except in the event that use of the book-entry-only system for the Bonds is discontinued.

To facilitate subsequent transfers, all Bonds deposited by Direct Participants with DTC are registered in the name of DTC's partnership nominee, Cede & Co., or such other name as may be requested by an authorized representative of DTC. The deposit of Bonds with DTC and their registration in the name of Cede & Co. or such other DTC nominee do not effect any change in beneficial ownership. DTC has no knowledge of the actual Beneficial Owners of the Bonds; DTC's records reflect only the identity of the Direct Participants to whose accounts such Bonds are credited, which may or may not be the Beneficial Owners. The Direct and Indirect Participants will remain responsible for keeping account of their holdings on behalf of their customers.

Conveyance of notices and other communications by DTC to Direct Participants, by Direct Participants to Indirect Participants, and by Direct Participants and Indirect Participants to Beneficial Owners will be governed by arrangements among them, subject to any statutory or regulatory requirements as may be in effect from time to time.

Beneficial Owners of Bonds may wish to take certain steps to augment the transmission to them of notices of significant events with respect to the Bonds, such as redemptions, tenders, defaults and proposed amendments to the Bond documents. For example, Beneficial Owners of the Bonds may wish to ascertain that the nominee holding the Bonds for their benefit has agreed to obtain and transmit notices to Beneficial Owners. In the alternative, Beneficial Owners may wish to provide their names and addresses to the registrar and request that copies of notices be provided directly to them.

Redemption notices shall be sent to DTC. If less than all of the Bonds are being redeemed, DTC's practice is to determine by lot the amount of the interest of each Direct Participant in such Bond to be redeemed.

Neither DTC nor Cede & Co. (nor any other DTC nominee) will consent or vote with respect to the Bonds unless authorized by a Direct Participant in accordance with DTC's procedures. Under its usual procedures, DTC mails an Omnibus Proxy to the Issuer as soon as possible after the record date. The Omnibus Proxy assigns Cede & Co.'s consenting or voting rights to those Direct Participants to whose accounts Bonds are credited on the record date (identified in a listing attached to the Omnibus Proxy).

Redemption proceeds and principal and interest payments on the Bonds will be made to Cede & Co., or such other nominee as may be requested by an authorized representative of DTC. DTC's practice is to credit Direct Participants' accounts upon DTC's receipt of funds and corresponding detailed information from the Company or the Trustee, on each payable date in accordance with their respective holdings shown on DTC's records. Payments by Participants to Beneficial Owners will be governed by standing instructions and customary practices, as is the case with securities held for the accounts of customers in bearer form or registered in "street name," and will be the responsibility of such Participant and not of DTC, the Company, the Trustee or the Issuer, subject to any statutory or regulatory requirements as may be in effect from time to time. Payment of redemption proceeds and principal and interest payments to Cede & Co. (or such other nominee as may be requested by an authorized representative of DTC) is the responsibility of the Trustee, disbursement of such payments to Direct Participants will be the responsibility of DTC, and disbursement of such payments to the Beneficial Owners will be the responsibility of Direct and Indirect Participants.

A Beneficial Owner shall give notice to elect to have its Bonds purchased or tendered, through its Participant, to the Trustee and Remarketing Agent, and shall effect delivery of such Bonds by causing the Direct Participant to transfer the Participant's interest in the Bonds, on DTC's records, to the Remarketing Agent. The requirement for physical delivery of the Bonds in connection with an optional tender or a mandatory tender for purchase will be deemed satisfied when the ownership rights in the Bonds are transferred by Direct Participants on DTC's records and followed by a book-entry credit of tendered Bonds to the Remarketing Agent's DTC account.

DTC may discontinue providing its services as depository with respect to the Bonds at any time by giving reasonable notice to the Issuer or the Trustee. Under such circumstances, in the event that a successor depository is not obtained, certificates for the Bonds are required to be printed and delivered. The Issuer may decide to discontinue use of the system of book-entry-only transfers through DTC (or a successor Securities Depository) with respect to the Bonds. In that event, certificates for the Bonds will be printed and delivered and thereafter, transfer, exchange, and replacement of Bonds would be governed by the applicable terms of the Indenture.

The information in this section concerning DTC and DTC's book-entry-only system has been obtained from sources that the Issuer, the Company and the Trustee believe to be reliable, but none of the Issuer, the Company or the Trustee takes any responsibility for the accuracy of such statements. None of the Issuer, the Company or the Trustee has any responsibility for the performance by DTC or its Participants of their respective obligations as described herein or under the rules and procedures governing their respective operations.

None of the Issuer, the Underwriter, the Company, the Letter of Credit Bank, the Trustee or any agent for payment on or registration of transfer or exchange of any Bond will have any responsibility or obligation to Direct Participants, Indirect Participants or

the persons for whom they act as nominees with respect to the accuracy of the records of DTC, its nominee or any Direct Participant with respect to any ownership interest in the Bonds, or payments to, or the providing of notice for, Direct Participants, Indirect Participants, or beneficial owners or other action taken by DTC, or its nominee, Cede & Co., as the sole owners of the Bonds.

Security for the Bonds

The Bonds will be special obligations of the Issuer, the principal of and premium, if any, and interest on which will be payable solely from (i) the payments to be made by the Company under the Agreement and the Note, which are pledged to the Trustee and (ii) the funds drawn under the Letter of Credit. The pledge does not extend to funds to which the Trustee is entitled in its own right as fees, reimbursement, indemnity or otherwise. The Bonds will not be secured by a mortgage or security interest in the Project or any other property of the Company. The Agreement provides that Loan Payments will be paid to the Trustee by the Company for the account of the Issuer.

THE LETTER OF CREDIT AND REIMBURSEMENT AGREEMENT

In addition to the descriptions of certain provisions of the Letter of Credit and the Reimbursement Agreement contained elsewhere herein, the following is a summary of certain provisions of the Letter of Credit and the Reimbursement Agreement and does not purport to be comprehensive or definitive. All references herein to the Letter of Credit or the Reimbursement Agreement are qualified in their entirety by reference to the Letter of Credit or the Reimbursement Agreement, as applicable, for the detailed provisions thereof. Any future credit agreement or reimbursement agreement pursuant to which an Alternate Letter of Credit is issued may have terms substantially different from those described below.

The Letter of Credit

Concurrently with the issuance of the Bonds, the Company will cause to be delivered to the Trustee the Letter of Credit issued by the Letter of Credit Bank, in the initial aggregate stated amount of $65,747,945. Under the Letter of Credit, the Trustee will be permitted to draw up to (a) an amount sufficient to pay (i) the principal of the Bonds when due at maturity, redemption or acceleration and (ii) the portion of the Purchase Price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the principal amount of such Bonds, plus (b) an amount equal to 35 days' interest on the Bonds at a maximum rate of 12% per annum to pay (i) interest on the Bonds when due and (ii) the portion of the Purchase Price of the Bonds tendered to the Trustee and not remarketed or for which remarketing proceeds have not been timely received by the draw time under the Letter of Credit corresponding to the accrued interest on such Bonds. The Letter of Credit will expire on June 26, 2017 or on the earliest occurrence of one or more events described below. The Letter of Credit may be extended from time to time by the Letter of Credit Bank in its discretion, unless terminated earlier pursuant to its terms.

The Letter of Credit is subject to termination on (a) the Letter of Credit Bank's close of business on June 26, 2017 (unless extended from time to time), (b) the earlier of (1) the fifteenth calendar day following conversion of all of the Bonds to a rate other than a Daily Rate or Weekly Rate and (2) the date on which the Letter of Credit Bank honors a drawing under the Letter of Credit on or after the conversion of all of the Bonds to a rate other than a Daily Rate or Weekly Rate, (c) the fifteenth calendar day following the Letter of Credit Bank's receipt of a notice of termination from the Trustee, (d) the date on which an Acceleration Drawing (as defined in the Letter of Credit) is honored by the Letter of Credit Bank, (e) the fifteenth calendar day after receipt by the Trustee of a written notice from the Letter of Credit Bank stating that there is an event of default (as defined in the Reimbursement Agreement) under the Reimbursement Agreement and directing the Trustee either to accelerate the Bonds or to effect a mandatory tender of the Bonds, and (f) the date on which the Letter of Credit Bank honors a Stated Maturity Drawing (as defined in the Letter of Credit).

The stated amount of the Letter of Credit (originally $65,747,945) is subject to adjustment for payments made by the Letter of Credit Bank to the Trustee pursuant to drawings under the Letter of Credit. Payments made (i) pursuant to drawings on the Letter of Credit to make scheduled principal payments on the Bonds, (ii) to pay the unpaid principal and accrued interest on the Bonds on redemption, and (iii) to pay the unpaid principal and accrued interest on the Bonds upon acceleration, permanently reduce the principal component of the stated amount of the Letter of Credit by an amount equal to such payments. Payments made pursuant to drawings on the Letter of Credit to pay interest on the Bonds and to pay the Purchase Price of Bonds tendered to the Trustee in accordance with the Indenture will reduce the stated amount by an amount equal to such payments; provided that (i) such amounts reduced with respect to the payment of accrued and unpaid interest only are reinstated automatically upon payment of such interest drawings by the Letter of Credit Bank and (ii) such amounts reduced with respect to drawings to pay the Purchase Price of tendered Bonds are reinstated upon notice from the Trustee when such Bonds are remarketed and the Letter of Credit Bank is reimbursed for such drawing.

Replacement of Letter of Credit

The Company may surrender the Letter of Credit or replace the Letter of Credit with an Alternate Letter of Credit or other facility meeting the requirements of the Indenture. The Bonds will be subject to mandatory tender for purchase (i) on the date five Business Days prior to the date of the surrender of the Letter of Credit without the delivery of an Alternate Letter of Credit or (ii) on the date of the replacement of the Letter of Credit with an Alternate Letter of Credit.

The Reimbursement Agreement

In addition to the description of certain provisions of the Reimbursement Agreement contained elsewhere herein, the following is a brief summary of certain provisions of the Reimbursement Agreement and does not purport to be comprehensive or definitive. All references herein to the Reimbursement Agreement are qualified in their entirety by reference to the Reimbursement Agreement for the detailed provisions thereof.

The Letter of Credit will be issued pursuant to a Reimbursement Agreement between the Company and the Letter of Credit Bank.

The Reimbursement Agreement contains, among other matters, representations, warranties and covenants on the part of the Company, the breach of which or material inaccuracy of which entitles the Letter of Credit Bank to notify the Trustee of an "event of default" (as defined in the Reimbursement Agreement) under the Reimbursement Agreement and directing the Trustee either to accelerate the Bonds or to effect a mandatory tender of the Bonds. The following events constitute "events of default" under the Reimbursement Agreement:

(a) The Company shall default in (i) the payment of any amount payable to the Letter of Credit Bank in reimbursement of any drawing under a Letter of Credit within three days after the same becomes due and payable; or (ii) the failure to make any other payment of fees or other amounts payable under the Reimbursement Agreement when the same becomes due and payable and such default shall continue unremedied for five or more calendar days; or

(b) Any representation or warranty made by the Company in the Reimbursement Agreement or by the Company (or any of its officers) in connection with the Reimbursement Agreement or in any certificate, financial or other statement furnished by the Company pursuant to the Reimbursement Agreement or any document related thereto shall prove to have been incorrect in any material respect when made; or

(c) (i) The Company shall fail to perform or observe certain specified terms, covenants or agreements contained in the Reimbursement Agreement (e.g., maintenance of existence, failure to give notice within five days after obtaining knowledge of a default, restriction on mergers and consolidations, restriction on disposition of any of the Company's equity in its subsidiaries, subjecting Bonds purchased with the Letter of Credit proceeds to be registered in the name of the Letter of Credit Bank, causing or providing notice of an optional redemption or purchase or change in interest rate determination method (other than to or from a Daily Rate or a Weekly Rate) resulting in a mandatory redemption or purchase unless sufficient funds are deposited on or prior to the date of such redemption or purchase or unless such notice is conditional upon receipt of such funds, agreeing to certain amendments to the Indenture, making or amending references to the Letter of Credit Bank in this Official Statement, use of Letter of Credit proceeds for a purpose other than payment of principal of, interest on, redemption price of and Purchase Price of the Bonds, a disposition by the Company or any of its subsidiaries of certain assets, creation by the Company and its subsidiaries of certain liens and encumbrances, restriction on entering into certain restrictive agreements, or (ii) the Company shall fail to perform or observe any other term, covenant or agreement contained in the Reimbursement Agreement or any other Loan Document (as defined in the Reimbursement Agreement) if such failure shall remain unremedied for 30 days after written notice thereof shall have been given to the Company; or

(d) Any event shall occur or condition shall exist under any agreement or instrument relating to debt of the Company (but excluding debt outstanding under the Reimbursement Agreement) or any subsidiary outstanding in a principal or notional amount of at least $50,000,000 in the aggregate if the effect of such event or condition is to accelerate or require early termination of the maturity or tenor of such debt, or any such debt shall be declared to be due and payable, or required to be prepaid or redeemed (other than by a regularly scheduled required prepayment or redemption), terminated, purchased or defeased, or an offer to prepay, redeem, purchase or defease such debt shall be required to be made, in each case prior to the stated maturity or the original tenor thereof; or

(e) The Company or any subsidiary shall generally not pay its debts as such debts become due, or shall admit in writing its inability to pay its debts generally, or shall make a general assignment for the benefit of creditors; or any proceeding shall be instituted by or against the Company or any subsidiary seeking to adjudicate it a bankrupt or insolvent, or seeking liquidation, winding up, reorganization, arrangement, adjustment, protection, relief, or composition of it or its debts under any law relating to bankruptcy, insolvency or reorganization or relief of debtors, or seeking the entry of an order for relief or the appointment of a receiver, trustee, custodian or other similar official for it or for any substantial part of its property and, in the case of any such proceeding instituted against it (but not instituted by it), either such proceeding shall remain undismissed or unstayed for a period of 60 days, or any of the actions sought in such proceeding (including, without limitation, the entry of an order for relief against, or the appointment of a receiver, trustee, custodian or other similar official for, it or for any substantial part of its property) shall occur; or the Company or any subsidiary shall take any corporate action to authorize any of the actions set forth above in this subsection (e); or

(f) Any judgment or order for the payment of money in excess of $50,000,000 in the case of the Company or any subsidiary to the extent not paid or covered by insurance shall be rendered against the Company or any subsidiary and either (i) enforcement proceedings shall have been commenced by any creditor upon such judgment or order or (ii) there shall be any period of 30 consecutive days during which a stay of enforcement of such judgment or order, by reason of a pending appeal or otherwise, shall not be in effect; or

(g) Certain events related to employee benefit matters shall have occurred and the liability of the Company and certain of its affiliates related to such employee benefit related event exceeds $50,000,000; or

(h) An "Event of Default" under and as defined in the Indenture shall have occurred and be continuing; or

(i) There shall be no Remarketing Agreement in effect at a time when support for the payment of principal and purchase price of and interest on any Bonds is required to be provided by the Company pursuant to the Indenture.

THE LOAN AGREEMENT

Loan of Proceeds

The Issuer will loan the proceeds of the sale of the Bonds to the Company, in accordance with the Loan Agreement and the Indenture.

Term of Loan Agreement

The term of the Loan Agreement will continue until such time as all of the outstanding Bonds are fully paid (or provision has been made for such payment) pursuant to the Indenture and all other money payable by the Company under the Loan Agreement shall have been paid.

Payments

The Company will make payments on the Loan Agreement which will be sufficient to pay, when due, the principal of, and premium, if any, interest on, and Purchase Price of, the Bonds. To evidence the obligations of the Company to make the Loan Payments and repay the Loan, the Company will, concurrently with the issuance of the Bonds, execute and deliver the Note to the Trustee, as assignee of the Issuer under the Indenture, in an aggregate principal amount equal to the aggregate principal amount of the Bonds. The Company will receive as a credit against its obligations to make payments under the Agreement with respect to the Bonds all payments made by the Letter of Credit Bank under the Letter of Credit.

Obligations Unconditional

The obligations of the Company to make Loan Payments and other payments required to be made pursuant to the Loan Agreement are absolute and unconditional, and the Company will make such payments without abatement, diminution or deduction regardless of any cause or circumstances whatsoever including, without limitation, any defense, set-off, recoupment or counterclaim which the Company may have or assert against the Issuer, the Trustee, the Remarketing Agent, the Letter of Credit Bank or any other Person.

Maintenance and Modification

During the term of the Loan Agreement, the Company will use its best efforts to keep and maintain, or cause to be kept and maintained, the Project, including all appurtenances thereto and any personal property therein or thereon, in satisfactory operating order, repair, condition and appearance, subject to reasonable wear and tear, so that the Project will continue to constitute a facility that can be financed by the Issuer under the Act for the purpose for which it was designed. Subject to certain conditions, the Company has the right, from time to time, to remodel the Project or make additions, modifications and improvements thereto, the cost of which must be paid by the Company. The Company also has the right, subject to certain conditions, to substitute or remove any portion of the Project.

Tax Exemption

The Company will covenant and represent in the Loan Agreement that it has taken and caused or required to be taken and will take and cause or require to be taken all actions that may be required of it for the interest on the Bonds to be and remain excluded from the gross income of the owners thereof for federal income tax purposes, and that it has not taken or permitted to be taken on its behalf, and it will not take or permit to be taken on its behalf, any action which, if taken, would adversely affect that exclusion under the provisions of the Code.

Assignment of the Loan Agreement

The Loan Agreement may be assigned in whole or in part by the Company only with the consent of the Issuer, subject to the following conditions: (a) no assignment will relieve the Company from primary liability for any of its obligations under the Loan Agreement; (b) any assignment by the Company must retain for the Company such rights and interests to permit it to perform its remaining obligations under the Loan Agreement, and any assignee from the Company shall assume the obligations of the Company hereunder to the extent of the interest assigned; (c) the Company will, within 30 days after the execution thereof, furnish or cause to be furnished to the Issuer, the Letter of Credit Bank and the Trustee a true and complete copy of each assignment together with any instrument of assumption; and (d) any assignment from the Company will not materially impair fulfillment of the purposes of the Project to be accomplished by operation of the Project as provided in the Loan Agreement.

Events of Default and Remedies

The Loan Agreement provides that the occurrence of one or more of the following events will constitute an "Event of Default:"

(a) The failure to pay any Loan Payment or any payment required to be made to pay the Purchase Price when due;

(b) The occurrence of an event of default described in paragraphs (a), (b) or (c) under *THE INDENTURE—Events of Defaults and Remedies*;

(c) Failure by the Company to observe and perform any other agreement, term or condition under the Loan Agreement, other than such failure which will result in an event of default described in (a) or (b) above, which continues for a period of 90 days after notice to the Company by the Issuer or the Trustee or such longer period as the Issuer and the Trustee may agree to in writing; *provided* that the failure shall not constitute an Event of Default if the Company institutes curative action within the applicable period and diligently pursues that action to completion;

(d) Any representation or warranty under the Loan Agreement shall not have been true in all material respects when made; and

(e) Certain events relating to bankruptcy, insolvency or reorganization of the Company.

A failure by the Company described in subparagraph (c) above is not a default under that subparagraph if it occurs by reason of certain courses, circumstances and events of force majeure specified in the Loan Agreement that are not reasonably within the control of the Company.

Whenever any Event of Default under a Loan Agreement has happened and is subsisting, the Issuer or the Trustee may take either or both of the following remedial steps:

(a) Inspect, examine and make copies of the books, records, accounts and financial data of the Company, only, however, insofar as they pertain to the Project; and

(b) Pursue all remedies to recover all amounts then due and thereafter to become due under the Loan Agreement and the Note, or to enforce the performance and observance of any other obligation or agreement of the Company under those instruments.

So long as the Letter of Credit is in full force and effect and the Letter of Credit Bank has not wrongfully dishonored a drawing under the Letter of Credit or wrongfully repudiated the Letter of Credit, the exercise of remedies under the Loan Agreement with respect to Events of Default (other than with respect to defaults resulting from failures of the Company relating to certain rights of the Issuer not assigned under the Indenture), and any waivers of Events of Default shall be at the direction or with the written consent of the Letter of Credit Bank.

Any amounts collected pursuant to action taken upon the happening of an Event of Default will be paid into the Bond Fund and applied in accordance with the provisions of the Indenture or, if the outstanding Bonds have been paid and discharged in accordance with the provisions of the Indenture, will be paid as provided in the Indenture for transfers of remaining amounts in the Bond Fund.

Amendments to the Loan Agreement

The Indenture provides that the Loan Agreement may be amended without the consent of or notice to the owners of the Bonds only as may be required or permitted (i) by the provisions of the Loan Agreement or the Indenture or for the purposes for which the Indenture may be amended or supplemented without the consent of the owners, (ii) for the purpose of curing any ambiguity or formal defect or omission in the Loan Agreement or (iii) in connection with any other change therein which, in the judgment of the Trustee, is not to the prejudice of the Trustee or the owners of the Bonds. Any other amendments to the Loan Agreement may be made only with the written approval or consent of (i) the owners of not less than a majority in aggregate principal amount of the Bonds outstanding and (ii) the Letter of Credit Bank, so long as the Letter of Credit is in effect and the Letter of Credit Bank has not wrongfully dishonored a drawing thereunder or wrongfully repudiated the Letter of Credit. An opinion of Bond Counsel to the effect that such action is permitted under the Act and the Indenture and will not adversely affect the exclusion from gross income of interest on the Bonds for federal income tax purposes (a "Favorable Opinion of Tax Counsel") is required for any amendment to the Loan Agreement.

THE INDENTURE

Additional information summarizing certain provisions of the Indenture is contained under the heading *THE BONDS*. So long as DTC or its nominee is the registered owner of the Bonds, all references to owners or holders shall mean DTC. See *THE BONDS - Book-Entry Only System* herein.

Pledge and Security

Pursuant to the Indenture, the payments to be made by the Company under the Loan Agreement and the Note will be assigned by the Issuer to the Trustee to secure the payment, when due, of the principal of, and premium, if any, and interest on, the Bonds. The Issuer will also absolutely and irrevocably assign to the Trustee all right, title and interest in and to the Letter of Credit Account in the Bond Fund and all moneys therein, and will mortgage, pledge and grant a security interest to the Trustee in all right, title and interest of the Issuer in and to (i) the Revenues (other than the Letter of Credit Account in the Bond Fund, and the moneys therein, assigned above), including without limitation, all Loan Payments and all other amounts receivable by the Issuer under the Loan Agreement in respect of repayment of the loan and (ii) the Note and the Loan Agreement (except certain rights to the payment of its costs and expenses, to indemnification and to enforce certain covenants of the Company); provided, that the Trustee, in case of an acceleration of the Bonds, will have a prior claim on the Bond Fund, other than money in the Letter of Credit Account, for the payment of its compensation and expenses.

Purchase Fund

The Trustee will apply money contained in the accounts described below maintained within the Purchase Fund as follows:

Remarketing Proceeds Account. Upon receipt of the proceeds of a remarketing of Bonds on a purchase date, the Trustee will directly deposit such proceeds, and will deposit only such proceeds, in the Remarketing Proceeds Account for application to the Purchase Price of the Bonds; provided that, at any time when the Letter of Credit is in effect, proceeds of any remarketing of Bonds to the Issuer, the Company or any affiliate of either of them and proceeds of the remarketing of any other Company-Held Bonds and any Bank-Owned Bonds which have been remarketed will be held and maintained in a subaccount for the benefit of the Letter of Credit Bank, separated and segregated from all other money in the Remarketing Proceeds Account. Upon instruction from the Letter of Credit Bank, any amount held by the Trustee in the subaccount described in the preceding sentence will be paid to the Letter of Credit Bank. Neither the Issuer nor the Company will have any interest in the Remarketing Proceeds Account.

Letter of Credit Purchase Account. Upon receipt of the immediately available funds provided to the Trustee under the Letter of Credit pursuant to the Indenture, the Trustee will directly deposit such money, and will deposit only such money, in the Letter of Credit Purchase Account for application to the Purchase Price of the Bonds. Any amounts deposited in the Letter of Credit Purchase Account and determined by the Trustee to be not needed with respect to any purchase date for the payment of the Purchase Price for any Bonds will be promptly returned following such determination to the Letter of Credit Bank with written notice to the Company. Neither the Issuer nor the Company will have any interest in the Letter of Credit Purchase Account.

Company Purchase Account. Upon receipt of immediately available funds provided to the Trustee by the Company pursuant to the Indenture, the Trustee shall directly deposit such money, and shall deposit only such money, in the Company Purchase Account for application to the Purchase Price of the Bonds. Any amounts deposited in the Company Purchase Account and determined by the Trustee to be not needed with respect to any purchase date for the payment of the Purchase Price for any Bonds shall be promptly returned following such determination to the Company.

Bond Fund

Payments made by the Company under the Agreement with respect to the Bonds and certain other amounts specified in the Indenture will be deposited in the Bond Fund. The Trustee will apply money contained in the accounts described below maintained within the Bond Fund as follows:

(a) Interest Account. The Trustee, on each Interest Payment Date, will withdraw and apply from moneys on deposit in the Interest Account an amount sufficient to pay interest on the outstanding Bonds on such Interest Payment Date; *provided, however*, when the Letter of Credit or an Alternate Letter of Credit is in effect, the Trustee, on each Interest Payment Date, shall withdraw and apply moneys in the Interest Account, if any, to reimburse the Letter of Credit Bank for draws on the Letter of Credit or the Alternate Letter of Credit pursuant to the Indenture.

(b) Principal Account. The Trustee, on each Principal Payment Date (as defined in the Indenture), will withdraw and apply from moneys on deposit in the Principal Account, an amount equal to the principal becoming due on the Bonds on such Principal Payment Date (other than a redemption date). Money in such Principal Account will be used and withdrawn by the Trustee on each Principal Payment Date solely for the payment of the principal of outstanding Bonds; *provided, however*, when the Letter of Credit or an Alternate Letter of Credit is in effect, the Trustee will apply such amounts, if any, to reimburse the Letter of Credit Bank for draws on the Letter of Credit or the Alternate Letter of Credit pursuant to the Indenture.

(c) Redemption Account. The Trustee, on or before each redemption date, will withdraw and apply from moneys on deposit in the Redemption Account amounts required to pay the principal of and premium, if any, and accrued interest on Bonds to be redeemed prior to their stated maturity. Money in such Redemption Account will be used and withdrawn by the Trustee on each redemption date solely for the payment of the principal of and premium, if any, and accrued interest on outstanding Bonds upon the redemption thereof prior to their stated maturity; *provided, however*, when the Letter of Credit or an Alternate Letter of Credit is in effect, the Trustee shall apply such amounts, if any, to reimburse the Letter of Credit Bank for draws on the Letter of Credit or the Alternate Letter of Credit pursuant to the Indenture.

(d) Letter of Credit Account. The Trustee will directly deposit, or cause to be directly deposited, the proceeds of draws on the Letter of Credit or an Alternate Letter of Credit to pay interest on and principal of the Bonds in such Letter of Credit Account, and shall deposit only those proceeds therein. Money in such Letter of Credit Account will be used and withdrawn by the Trustee on each Interest Payment Date and each Principal Payment Date first, before any other source of funds, to pay the principal of and interest on the Bonds; *provided, however*, that in no event shall moneys in such Letter of Credit Account be used to pay interest and premium on or principal of Bonds that are Bank-Owned Bonds or Company-Held Bonds (each as defined in the Indenture) if the Letter of Credit or Alternate Letter of Credit does not permit drawings thereunder with respect to Bank-Owned Bonds or Company-Held Bonds. Amounts in the Letter of Credit Account shall be held uninvested. Neither the Issuer nor the Company shall have any interest in the Letter of Credit Account.

(e) Payments by Company. If during any period that a Letter of Credit is in effect there is not sufficient money in the Letter of Credit Account to make the payments on an Interest Payment Date or Principal Payment Date, the Trustee will make such payments from money provided by the Company and deposited into the other accounts of the Bond Fund.

Refunding Fund

The proceeds received from the sale of the Bonds (other than any accrued interest) will be deposited in the Refunding Fund. Moneys on deposit in the Refunding Fund shall be transferred to the Refunded Bonds Trustee on the date specified in the Indenture for deposit into the purchase fund created in the Refunded Bonds Indenture and used, together with other moneys provided by the Company, to purchase the Refunded Bonds. After such purchase of the Refunded Bonds, the Refunded Bonds Trustee will thereupon retire, cancel and extinguish the Refunded Bonds so that the same are no longer outstanding under the Refunded Bonds Indenture.

Investment of Moneys Held by the Trustee

Moneys deposited in the Refunding Fund and in the accounts maintained within the Bond Fund (except the Letter of Credit Account) will be invested at the direction of the Company in Permitted Investments (as defined in the Indenture). Moneys held in the Purchase Fund will be held uninvested.

The Loan Agreement provides that the Company and the Issuer shall take no action, nor shall the Company approve the Trustee taking any action, or making any investment or use of the proceeds of the Bonds, which would cause the Bonds to be "arbitrage bonds" within the meaning of Section 148 of the Code.

Events of Default and Remedies

The following events are Events of Default under the Indenture:

(a) Default in the payment when due of any interest on any Bond;

(b) Default in the due and punctual payment of the principal of, or premium, if any, on any Bond, whether at the stated maturity thereof, or upon unconditional proceedings for redemption thereof;

(c) Default in the due and punctual payment of the Purchase Price of any Bond required to be purchased in accordance with its terms;

(d) Default in the performance or observance of any other of the covenants, agreements or conditions on the part of the Issuer in the Indenture or in the Bonds, continuing 30 days after delivery of notice thereof;

(e) The occurrence and continuance of an event of default under the Loan Agreement as described under *THE LOAN AGREEMENT – Events of Default and Remedies*; or

(f) Receipt by the Trustee of a written notice from the Letter of Credit Bank stating that an event of default has occurred under the Reimbursement Agreement and directing the Trustee to declare the principal of the outstanding Bonds immediately due and payable.

Upon the occurrence and continuance of an Event of Default under (a), (b) or (c) above the Trustee may, and upon the written request of the owners of at least 25% in aggregate principal amount of the Bonds then outstanding shall, declare the principal of and accrued interest on the outstanding Bonds to be due and payable immediately. If an Event of Default under paragraph (d) or (e) above occurs and is continuing, the Trustee may, and upon the request of the owners of at least 25% in aggregate principal amount of the Bonds then outstanding, shall, declare the principal of and accrued interest on the outstanding Bonds to be due and payable immediately, *provided, however,* when the Letter of Credit is in effect and so long as the Letter of Credit Bank has not wrongfully dishonored a drawing under the Letter of Credit (or otherwise repudiated the Letter of Credit), the Trustee will make such a declaration only with the written consent of the Letter of Credit Bank. If an Event of Default under paragraph (f) above occurs and is continuing, the Trustee shall declare the principal of and accrued interest on the outstanding Bonds to be due and payable immediately.

Upon any such declaration, the principal of and accrued interest on the outstanding Bonds shall be due and payable immediately. Notwithstanding anything else herein to the contrary, interest on the outstanding Bonds will cease to accrue immediately upon a declaration of acceleration for an Event of Default under (f) above. When the Letter of Credit is in effect, the Trustee shall, immediately upon a declaration of acceleration, draw upon the Letter of Credit to pay the principal of and interest on the outstanding Bonds; *provided*, that in no event shall a drawing be made with respect to Bank-Owned Bonds or Company-Held Bonds, if the Letter of Credit by its terms does not permit such a drawing. In the event the Letter of Credit Bank fails to honor a draw on the Letter of Credit (or otherwise repudiates the Letter of Credit) in accordance with the immediately preceding sentence, the Trustee shall immediately notify the Company of such failure and shall request that the Company transfer sufficient amounts to pay the principal of and interest on the Bonds.

The Trustee may rescind an acceleration of the Bonds and its consequences if (1) all payment defaults with respect to the Bonds have been cured and all reasonable fees and charges of the Trustee, including reasonable attorneys' fees, have been paid, and (2) the Bondholders have not been notified of the acceleration, and (3) while the Letter of Credit is in effect, the Letter of Credit Bank has notified the Trustee in writing (i) that the amount available to be drawn under the Letter of Credit has been reinstated so as to be available in any amount equal to the principal amount of the Bonds outstanding less the principal amount of any Bank-Owned Bonds, plus the applicable Letter of Credit Interest Amount (as defined in the Indenture) and any required premium coverage and (ii) that the Letter of Credit Bank has rescinded in writing any event of default under the Reimbursement Agreement. Except as provided in this section, the Trustee will not declare the Bonds to be due and payable.

If an Event of Default occurs and is continuing, the Trustee may pursue any available remedy by proceeding at law or in equity to collect the principal of and premium, if any, or interest on the Bonds or to enforce the performance of any provision of the Bonds or the Indenture. So long as the Letter of Credit is in effect and the Letter of Credit Bank has not wrongfully dishonored a drawing thereunder or wrongfully repudiated the Letter of Credit, the Trustee will pursue any remedy only at the direction of or with the consent of the Letter of Credit Bank.

A majority in aggregate principal amount of the outstanding Bonds by notice to the Trustee may waive an existing Event of Default and its consequences; *provided, however*, that, when the Letter of Credit is in effect and so long as the Letter of Credit Bank has not wrongfully dishonored a drawing under such Letter of Credit or wrongfully repudiated the Letter of Credit, no such waiver shall be effective with respect to the Bonds unless and until the Letter of Credit Bank has notified the Trustee in writing (i) that the amount available to be drawn under the Letter of Credit has been reinstated so as to be available in an amount equal to the principal amount of the Bonds outstanding less the principal amount of any Bank-Owned Bonds, plus the applicable Letter of Credit Interest Amount and any required premium coverage, (ii) that the Letter of Credit Bank has rescinded in writing the notice of default, and (iii) that the Letter of Credit Bank has waived in writing any event of default under the Reimbursement Agreement. When an Event of Default is waived, it is cured and stops continuing, but no such waiver will extend to any subsequent or other Event of Default or impair any right consequent to it.

When there is a Letter of Credit in effect and so long as the Letter of Credit Bank has not wrongfully dishonored a drawing under such Letter of Credit or wrongfully repudiated the Letter of Credit, the Letter of Credit Bank may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on it with respect to the Bonds. When there is no Letter of Credit in effect or when the Letter of Credit Bank has wrongfully dishonored a drawing under the Letter of Credit or wrongfully repudiated the Letter of Credit, the holders of a majority in aggregate principal amount of Bonds outstanding may direct the time, method and place of conducting any proceeding for any remedy available to the Trustee or of exercising any trust or power conferred on it.

An owner of a Bond may not pursue any remedy with respect to the Indenture or the Bonds unless (a) the owner gives the Trustee notice stating that an Event of Default is continuing, (b) the owners of at least 25% in aggregate principal amount of the outstanding Bonds make a written request to the Trustee to pursue the remedy, (c) such owner or owners offer to the Trustee indemnity satisfactory to the Trustee against any loss, liability or expense, (d) the Trustee does not comply with the request within 60 days after receipt of the request and the offer of indemnity, and (e) with respect to the Bonds, the Letter of Credit is either not in effect or the Letter of Credit Bank has wrongfully dishonored a drawing under the Letter of Credit or wrongfully repudiated the Letter of Credit.

Except as described below, funds drawn under the Letter of Credit will be used only for the payment of principal of and interest on, premium, if any (to the extent that the Letter of Credit covers premium) and the Purchase Price of, the Bonds, as provided in the Letter of Credit. If the Trustee collects any money pursuant to the Indenture or if any moneys shall be on deposit in the Bond Fund at the time of acceleration of the Bonds or shall be deposited into the Bond Fund as a result of such an acceleration, it will pay out such monies in the following order: first to the Trustee for amounts to which it is entitled under such Indenture (*provided*, that if such money constitutes proceeds of a draw under the Letter of Credit, the Trustee shall only use such proceeds to pay the owners of the Bonds); second to owners for amounts due and unpaid on the Bonds for principal, premium and interest, ratably, without preference or priority of any kind, according to the amounts due and payable on the Bonds for principal, premium and interest, respectively, third to the Letter of Credit Bank to the extent it certifies that the Company is indebted to it on account of draws Letter of Credit or otherwise under the Reimbursement Agreement; and fourth to the Company (*provided*, that if such money constitutes proceeds of a draw under the Letter of Credit, the Trustee shall pay the Letter of Credit Bank rather than the Company). Any lien of the Trustee provided for in the Indenture will in no event apply to any funds drawn under the Letter of Credit or to other funds held for the benefit of the Bondholders. The Trustee may fix a payment date for any payment to the Bondholders.

Supplemental Indentures

The Issuer and the Trustee may, without the consent of, or notice to, any of the Bondholders, enter into such indenture or indentures supplemental to the Indenture as shall not be inconsistent with the terms and provisions thereof:

(a) to cure any ambiguity, defect or omission in the Indenture, or otherwise amend the Indenture, in such manner as shall not in the opinion of the Trustee impair the security under the Indenture;

(b) to grant to or confer upon the Trustee for the benefit of the Bondholders any additional rights, remedies, powers or authorities that may lawfully be granted to or conferred upon the Bondholders or the Trustee;

(c) to evidence any succession to the Issuer and the assumption by its successor of the covenants, agreements and obligations of the Issuer under the Indenture, the Agreement and the Bonds, to add additional covenants of the Issuer or surrender any right or power therein conferred upon the Issuer;

(d) to subject to the pledge of the Indenture additional revenues, properties or collateral, which may be accomplished by, among other things, entering into instruments with the Company and/or other persons providing for further security, covenants, limitations or restrictions for the benefit of the Bonds;

(e) to modify the Indenture to permit qualification under the Trust Indenture Act of 1939, as amended, or any similar statute at the time in effect;

(f) to amend any provision pertaining to matters under federal income tax laws, including Section 148(f) of the Code;

(g) to authorize different Authorized Denominations of the Bonds and to make correlative amendments and modifications to the Indenture regarding exchangeability of Bonds of different Authorized Denominations, redemptions of portions of Bonds of particular Authorized Denominations and similar amendments and modifications of a technical nature;

(h) to increase or decrease the number of days specified for the giving of notices of mandatory tender and to make corresponding changes to the period for notice of redemption of the Bonds; *provided*, that no decreases in any such number of days will become effective except while the Bonds bear interest at a Daily Rate or a Weekly Rate and until 30 days after the Trustee has given notice to the owners of the Bonds;

(i) to provide for an uncertificated system of registering the Bonds or to provide for the change to or from a Book-Entry System for the Bonds;

(j) to evidence the succession of a new trustee or the appointment by the Trustee or the Issuer of a co-trustee;

(k) to make any change related to the Bonds that does not materially adversely affect the rights of any Bondholder; and

(l) to make any other changes to the Indenture that take effect as to any or all remarketed Bonds following a mandatory tender.

The Indenture also provides that the owners of not less than a majority in aggregate principal amount of the Bonds outstanding shall have the right, from time to time, to consent to and approve the execution by the Issuer and the Trustee of such other indenture or supplemental indentures as shall be deemed necessary and desirable by the Issuer and the Trustee for the purpose of modifying, altering, amending, adding to or rescinding, in any particular, any of the terms or provisions contained in the Indenture or in any supplemental indenture; *provided, however,* that nothing shall permit, without certain additional consents, (a) an extension of the maturity date of the principal of or the interest on any Bond; (b) a reduction in the principal amount of any Bond, the rate of interest thereon or any redemption premium; or (c) a reduction in the aggregate principal amount of the Bonds required for consent to such supplemental indenture or for actions related to amendments to the Loan Agreement. A Favorable Opinion of Bond Counsel is required for any supplement to the Indenture.

When the Letter of Credit is in effect and so long as the Letter of Credit Bank has not wrongfully dishonored a drawing under the Letter of Credit or wrongfully repudiated the Letter of Credit, no waiver of or amendment or supplement to the Indenture other than certain of those enumerated in the Indenture shall be made without the prior written consent of the Letter of Credit Bank to such amendment or supplement.

Discharge of the Indenture

If the whole amount of principal and interest due and payable on the Bonds has been paid and if, at the time of such payment, the Issuer shall have kept, performed and observed all the covenants and promises in such Bonds and in the Indenture required or contemplated to be kept, performed and observed by the Issuer or on its part on or prior to that time, then the Indenture shall be considered to have been discharged in respect of such Bonds and such Bonds shall cease to be entitled to the lien of the Indenture and such lien and all covenants, agreements and other obligations of the Issuer hereunder shall cease, terminate, become void and be completely discharged as to such Bonds.

No Personal Liability of Issuer's Officials

No covenant, stipulation, obligation or agreement of the Issuer contained in the Indenture will be or be deemed to be a covenant, stipulation, obligation or agreement of any present or future member, officer, agent or employee of the Issuer in other than his or her official capacity. No member of the Issuer or official executing the Bonds, the Indenture, the Loan Agreement or any amendment or supplement to the Indenture or the Loan Agreement will be liable personally on the Bonds or be subject to any personal liability or accountability by reason of the issuance or execution thereof.

Removal of Trustee

The Trustee may be removed by the owners of not less than a majority in principal amount of Bonds at the time outstanding or by the Issuer and the Company. The Trustee shall continue to serve as such until a successor Trustee shall be appointed under the Indenture and such successor Trustee has accepted such appointment.

THE REMARKETING AGREEMENT

U.S. Bancorp Investments, Inc. and U.S. Bank Municipal Securities Group, a Division of U.S. Bank National Association, have been appointed as the Remarketing Agent for the Bonds. If and to the extent the Company directs the Remarketing Agent to remarket the Bonds delivered for purchase pursuant to the Indenture, the Remarketing Agent, pursuant to and subject to the provisions of a remarketing agreement with the Company (the "Remarketing Agreement"), will offer for sale and use reasonable efforts to sell such Bonds at a price equal to 100% of the principal amount thereof plus accrued interest, if any, to the purchase date. The Remarketing Agent may resign by giving notice to the Issuer, the Company and the Trustee (such resignation will be effective upon the appointment of a successor remarketing agent or 30 days after such notice has been sent) and may suspend remarketing upon the occurrence of certain events. The Company may remove the Remarketing Agent at any time upon 30 days' notice and appoint a successor by notifying the Remarketing Agent, the Issuer and the Trustee.

THE TRUSTEE

The Bank of New York Mellon Trust Company, N.A. serves as trustee under other indentures providing for certain tax-exempt bonds for the benefit of the Company. The Company and certain of its affiliates maintain banking relationships with affiliates of The Bank of New York Mellon, N.A. and borrow from such affiliates from time to time. The Bank of New York Mellon Trust Company, N.A., and its affiliates, serve as trustee under other indentures with, or for the benefit of, affiliates of the Company.

UNDERWRITING

Subject to the terms and conditions set forth in a Bond Purchase Agreement ("Purchase Agreement") to be entered into between the Issuer and the Underwriter, the Underwriter has agreed to purchase the Bonds at a purchase price of 100% of the principal amount thereof. Under the terms and conditions of the Purchase Agreement, the Underwriter is committed to take and pay for all of the Bonds if any are taken. The Company has agreed to pay the Underwriter $97,500 as compensation and to reimburse the Underwriter for its reasonable expenses.

The Issuer has been advised by the Underwriter that the Bonds may be offered and sold to certain dealers (including dealers depositing Bonds into investment trusts) and others at prices lower than the public offering price set forth on the cover page of this Official Statement. After the Bonds are released for sale to the public, the public offering price and other selling terms may from time to time be varied by the Underwriter.

In connection with this offering and in compliance with applicable law and industry practice, the Underwriter may overallot or effect transactions which stabilize, maintain or otherwise affect the market price of the Bonds at levels above those which might otherwise prevail in the open market, including by entering into stabilizing bids. A stabilizing bid means the placing of a bid, or the effecting of any purchase, for the purpose of pegging, fixing or maintaining the price of a security. In general, purchases of a security for the purpose of stabilization could cause the price of the security to be higher than it might be in the absence of such purchases.

Neither the Issuer, the Company nor the Underwriter makes any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the Bonds. In addition, neither the Issuer, the Company nor the Underwriter makes any representation that the Underwriter will engage in such transactions or that such transactions, once commenced, will not be discontinued without notice.

Pursuant to an Inducement Letter, the Company has agreed to indemnify the Underwriter and the Issuer against certain civil liabilities, including liabilities under the federal securities laws, or contribute to payments that the Underwriter or the Issuer may be required to make in respect thereof.

In the ordinary course of its business, the Underwriter and certain of its affiliates have in the past and may in the future engage in investment banking, commercial banking or other transactions of a financial nature with the Company and its affiliates, for which it has received, or may receive, customary compensation.

"US Bancorp" is the marketing name of U.S. Bancorp and its subsidiaries, including U.S. Bank Municipal Securities Group, a Division of U.S. Bank National Association ("USB MSG"), which is serving as the Underwriter of the Bonds, and U.S. Bancorp Investments, Inc., which, along with USB MSG, is serving as Remarketing Agent for the Bonds.

CONTINUING DISCLOSURE AGREEMENT

The Company has agreed to deliver certain continuing disclosure information satisfying the requirements of Rule 15c2-12 ("Rule") under the 1934 Act. The Company will undertake in a written agreement for the benefit of the holders and beneficial owners of the Bonds (the "Continuing Disclosure Undertaking") to provide the Municipal Securities Rulemaking Board ("MSRB") as the sole nationally recognized securities repository through the MSRB's Electronic Municipal Market Access ("EMMA") certain financial and operating data concerning the Company. In addition, the Company will undertake, for the benefit of the holders and beneficial owners of the Bonds, to provide to the MSRB through EMMA, in a timely manner (not in excess of ten (10) business days after the occurrence of such event), notices of any of the events enumerated in the Rule. Notices of the aforesaid events and any filing to be made under the Continuing Disclosure Undertaking may be made solely by transmitting such filing to the MSRB through EMMA as provided at http://emma.msrb.org. The contents of such website do not constitute a part of this Official Statement.

The sole and exclusive remedy for breach or default under the Continuing Disclosure Undertaking is an action to compel specific performance of the undertakings of the Company and no person, including a holder of the Bonds, may recover monetary damages thereunder under any circumstances. A breach or default under the Continuing Disclosure Undertaking shall not constitute an event of default under the Indenture or the Agreement. In addition, if all or any part of the Rule ceases to be in effect for any reason, then, subject to the terms of the Continuing Disclosure Undertaking, the information required to be provided under the Continuing Disclosure Undertaking, insofar as the provision of the Rule no longer in effect required the provision of such information, shall no longer be required to be provided.

TAX EXEMPTION

In the opinion of Squire Patton Boggs (US) LLP, Bond Counsel, under existing law: (i) interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103(a) of the Code, except for interest on any Bond for any period during which it is held by a "substantial user" or a "related person" as those terms are used in Section 147(a) of the Code; (ii) interest on the Bonds is an item of tax preference under Section 57 of the Code for purposes of the federal alternative minimum tax imposed on individuals and corporations; and (iii) the Bonds, and all interest and income thereon, are exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. Bond Counsel expresses no opinion as to any other tax consequences regarding the Bonds.

The opinion on tax matters will be based on and will assume the accuracy of certain representations and certifications, and continuing compliance with certain covenants, of the Issuer and the Company contained in the transcript of proceedings and that are intended to evidence and assure the foregoing, including that the Bonds are and will remain obligations the interest on which is excluded from gross income for federal income tax purposes. Bond Counsel will not independently verify the accuracy of the Issuer's and the Company's certifications and representations or the continuing compliance with the Issuer's and the Company's covenants.

The opinion of Bond Counsel is based on current legal authority and covers certain matters not directly addressed by such authority. It represents Bond Counsel's legal judgment as to exclusion of interest on the Bonds from gross income for federal income tax purposes but is not a guaranty of that conclusion. The opinion is not binding on the Internal Revenue Service (the "IRS") or any court. Bond Counsel expresses no opinion about (i) the effect of future changes in the Code and the applicable regulations under the Code or (ii) the interpretation and the enforcement of the Code or those regulations by the IRS.

The Code prescribes a number of qualifications and conditions for the interest on state and local government obligations to be and to remain excluded from gross income for federal income tax purposes, some of which require future or continued compliance after issuance of the obligations. Noncompliance with these requirements by the Issuer or the Company may cause loss of such status and result in the interest on the Bonds being included in gross income for federal income tax purposes retroactively to the date of issuance of the Bonds. The Company and the Issuer have each covenanted to take the actions required of it for the interest on the Bonds to be and to remain excluded from gross income for federal income tax purposes, and not to take any actions that would adversely affect that exclusion. After the date of issuance of the Bonds, Bond Counsel will not undertake to determine (or to so inform any person) whether any actions taken or not taken, or any events occurring or not occurring, or any other matters coming to Bond Counsel's attention, may adversely affect the exclusion from gross income for federal income tax purposes of interest on the Bonds or the market value of the Bonds.

A portion of the interest on the Bonds earned by certain corporations may be subject to a federal corporate alternative minimum tax. In addition, interest on the Bonds may be subject to a federal branch profits tax imposed on certain foreign corporations doing business in the United States and to a federal tax imposed on excess net passive income of certain S corporations.

Under the Code, the exclusion of interest from gross income for federal income tax purposes may have certain adverse federal income tax consequences on items of income, deduction or credit for certain taxpayers, including financial institutions, certain insurance companies, recipients of Social Security and Railroad Retirement benefits, those that are deemed to incur or continue indebtedness to acquire or carry tax-exempt obligations, and individuals otherwise eligible for the earned income tax credit. The applicability and extent of these and other tax consequences will depend upon the particular tax status or other tax items of the owner of the Bonds. Bond Counsel will express no opinion regarding those consequences.

Payments of interest on tax-exempt obligations, including the Bonds, are generally subject to IRS Form 1099-INT information reporting requirements. If a Bond owner is subject to backup withholding under those requirements, then payments of interest will also be subject to backup withholding. Those requirements do not affect the excludability of such interest from gross income for federal income tax purposes.

Bond Counsel's engagement with respect to the Bonds ends with the issuance of the Bonds, and, unless separately engaged, Bond Counsel is not obligated to defend the Issuer, the Company or the owners of the Bonds regarding the tax status of interest on the Bonds in the event of an audit examination by the IRS. The IRS has a program to audit tax-exempt obligations to determine whether the interest thereon is includible in gross income for federal income tax purposes. If the IRS does audit the Bonds, under current IRS procedures, the IRS will treat the Issuer as the taxpayer and the beneficial owners of the Bonds will have only limited rights, if any, to obtain and participate in judicial review of such audit. Any action of the IRS, including but not limited to selection of the Bonds for audit, or the course or result of such audit, or an audit of other obligations presenting similar tax issues, may affect the market value for the Bonds.

Prospective purchasers of the Bonds upon their original issuance at prices other than the respective prices indicated on the cover of this Official Statement, and prospective purchasers of the Bonds at other than their original issuance, should consult their own tax advisers regarding other tax considerations such as the consequences of market discount, as to all of which Bond Counsel expresses no opinion.

Risk of Future Legislative Changes and/or Court Decisions

Legislation affecting tax-exempt obligations is regularly considered by the United States Congress and may also be considered by the State legislature. Court proceedings may also be filed, the outcome of which could modify the tax treatment of obligations such as the Bonds. There can be no assurance that legislation enacted or proposed, or actions by a court, after the date of issuance of the Bonds will not have an adverse effect on the tax status of interest on the Bonds or the market value or marketability of the Bonds. These adverse effects could result, for example, from changes to federal or state income tax rates, changes in the structure of federal or state income taxes (including replacement with another type of tax), or repeal (or reduction in the benefit) of the exclusion of interest on the Bonds from gross income for federal or state income tax purposes for all or certain taxpayers.

For example, recent presidential and legislative proposals would eliminate, reduce or otherwise alter the tax benefits currently provided to certain owners of state and local government bonds, including proposals that would result in additional federal income tax on taxpayers that own tax-exempt obligations if their incomes exceed certain thresholds. Investors in the Bonds should be aware that any such future legislative actions (including federal income tax reform) may retroactively change the treatment of all or a portion of the interest on the Bonds for federal income tax purposes for all or certain taxpayers. In such event, the market value of the Bonds may be adversely affected and the ability of holders to sell their Bonds in the secondary market may be reduced. The interest rates on the Bonds are not subject to adjustment in the event of any such change.

Investors should consult their own financial and tax advisers to analyze the importance of these risks.

LEGAL MATTERS

Certain legal matters relating to the authorization and validity of the Bonds will be subject to the approving opinion of Squire Patton Boggs (US) LLP, Bond Counsel, which will be furnished at the expense of the Company upon delivery of the Bonds, in substantially the form set forth as Appendix C (the "Bond Opinion"). The Bond Opinion will be limited to matters relating to authorization and validity of the Bonds and to the tax-exempt status of interest thereon as described in the section *TAX EXEMPTION*. Bond Counsel has not been engaged to investigate the financial resources of the Company or its ability to provide for payment of the Bonds, and the Bond Opinion will make no statement as to such matters or as to the accuracy or completeness of this Official Statement or any other information that may have been relied on by anyone in making the decision to purchase Bonds.

Certain legal matters will be passed upon by Jeffrey D. Cross or Thomas G. Berkemeyer, each as counsel for the Company. Jeffrey D. Cross is Deputy General Counsel of American Electric Power Service Corporation, an affiliate of the Company. Thomas G. Berkemeyer is Associate General Counsel of American Electric Power Service Corporation. Certain legal matters, other than the validity of the Bonds and the exclusion from gross income of interest thereon, will be passed upon by Hunton & Williams LLP, New York, New York, counsel for the Underwriter. Certain legal matters will be passed upon for the Letter of Credit Bank by its counsel, Winston & Strawn LLP. Squire Patton Boggs (US) LLP and Hunton & Williams LLP each act as counsel to certain affiliates of the Company for some matters.

The various legal opinions to be delivered concurrently with the delivery of the Bonds express the professional judgment of the attorneys rendering the opinions as to the legal issues explicitly addressed therein. In rendering a legal opinion, the attorney does not become an insurer or guarantor of the expression of professional judgment, of the transaction opined upon, or of the future performance of the parties to the transaction, nor does the rendering of an opinion guarantee the outcome of any legal dispute that may arise out of the transaction.

MISCELLANEOUS

The attached Appendices are an integral part of the Official Statement and must be read together with all of the balance of this Official Statement.

The Issuer does not assume any responsibility for the matters contained in this Official Statement other than information under *THE ISSUER*. All findings and determinations by the Issuer relating to the issuance and sale of the Bonds are, and have been, made by the Issuer for its own internal uses and purposes in performing its duties under West Virginia law.

APPENDIX A

KENTUCKY POWER COMPANY

Kentucky Power Company (the "Company") is engaged in the generation, transmission and distribution of electric power to approximately 172,000 retail customers in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. The Company owns 1,858 MW of generating capacity, including 780 MW which acquired it from Ohio Power Company in a year-end transaction. The Company uses its generation to serve its retail and other customers. As of December 31, 2013, the Company had 642 employees. The principal industries served by the Company include petroleum refining, coal mining and chemical production. The Company's principal executive offices are located at 1 Riverside Plaza, Columbus, Ohio, and the telephone number is (614) 716-1000.

AVAILABLE INFORMATION

On July 31, 2007, the Company filed a Form 15 under the Securities Exchange Act of 1934 (the "1934 Act"), which suspended its duty to file reports under Section 13 and 15(d) under the 1934 Act. Accordingly, the Company no longer files reports and other information with the Securities and Exchange Commission (the "SEC").

FINANCIAL STATEMENTS

Annex 1 to this Appendix A contains the balance sheets of the Company as of December 31, 2013 and 2012 and the statements of income, comprehensive income (loss), changes in common shareholder's equity and cash flows for each of the three years in the period ended December 31, 2013 and the related notes thereto. Annex 2 to this Appendix A contains the unaudited condensed balance sheets of the Company as of March 31, 2014 and December 31, 2013 and the unaudited condensed statements of income, comprehensive income (loss), changes in common shareholder's equity and statements of cash flows of the Company for the three months in the periods ended March 31, 2014 and 2013 and the related notes thereto.

RISK FACTORS

Investing in the Bonds involves risk. Please see the risk factors described below. Before making an investment decision, you should carefully consider these risks. The risks and uncertainties described are those presently known to us. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations, our financial results and the value of the Bonds.

GENERAL RISKS OF OUR REGULATED OPERATIONS

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction of additional transmission facilities, modernizing existing infrastructure as well as other initiatives. We provide service at rates approved by the Kentucky Public Service Commission (the "KPSC"). If the KPSC does not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished.

We may not recover costs incurred to begin construction on projects that are canceled.

Our business plan for the construction of new projects involves a number of risks, including construction delays, nonperformance by equipment and other third party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, we enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects is canceled for any reason, including our failure to receive necessary regulatory approvals and/or siting or environmental permits, we could incur significant cancellation penalties under the equipment purchase orders and construction contracts. In addition, if we have recorded any construction work or investments as an asset, we may need to impair that asset in the event the project is canceled.

Rate regulation may delay or deny full recovery of capital improvements, additions, storm damage operations and maintenance expense repairs and other costs.

We provide service at rates approved by the KPSC. These rates are generally regulated based on an analysis of our expenses incurred in a test year. Thus, KPSC-approved rates may or may not match our expenses at any given time. There may also be a delay between the timing of when these costs are incurred and when these costs are recovered. We often finance the operations and maintenance expense to repair facilities damaged by storms or other severe weather events until the operations and maintenance storm costs, including any deferred regulatory assets, are recovered in rates. We have also traditionally financed capital investments and improvements until the new asset was placed in service. Provided the asset was found to be a prudent investment, the asset was then added to rate base and entitled to a return through rate recovery. Similarly, long lead times in construction and scheduled repairs, the high costs of plant and equipment and volatile capital markets have heightened the risks involved in our capital investments, repairs and improvements. While we are actively pursuing strategies to accelerate rate recognition of investments and cash flow, including pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates, there can be no assurance that these will be adopted, that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will be done in a timely manner.

Certain of our revenues and results of operations are subject to risks that are beyond our control.

Our operations are structured to comply with all applicable federal and state laws and regulations and we take measures to minimize the risk of significant disruptions. Material disruptions at one or more of our operational facilities, however, could negatively impact our revenues, operating and capital expenditures and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials. We could experience unexpected but significant interruption due to several events, including, but not limited to:

- Major facility or equipment failure.
- An environmental event such as a serious spill or release.
- Fires, floods, droughts, earthquakes, hurricanes, tornados or other natural disasters.
- Wars, terrorist acts (including cyber-terrorism) or threats and other catastrophic events.
- Significant health impairments or disease events.
- Other serious operational problems.

PJM has changing market and transmission structures, which could affect our performance.

Our results are likely to be affected by differences in the market and transmission structures in PJM. The rules governing PJM may also change from time to time which could affect our costs or revenues. Because the manner in which PJM will evolve remains unclear, we are unable to assess fully the impact that changes in these power markets may have on our business.

We could be subject to higher costs and/or penalties related to mandatory reliability standards.

As a result of EPACT, owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the Federal Energy Regulatory Commission (the "FERC"). The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

RISKS RELATED TO MARKET, ECONOMIC OR FINANCIAL VOLATILITY AND OTHER RISKS

Our financial performance may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions.

Our performance is highly dependent on the successful operation of our generation, transmission and distribution facilities. Operating these facilities involves many risks, including:

- Operator error and breakdown or failure of equipment or processes.

- Operating limitations that may be imposed by environmental or other regulatory requirements.
- Labor disputes.
- Compliance with mandatory reliability standards, including mandatory cyber security standards.
- Information technology failure that impairs our information technology infrastructure or disrupts normal business operations.
- Information technology failure that affects our ability to access customer information or causes us to lose confidential or proprietary data that materially and adversely affects our reputation or exposes us to legal claims.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by our suppliers and other factors.
- Catastrophic events such as fires, earthquakes, explosions, hurricanes, tornados, ice storms, terrorism (including cyber-terrorism), floods or other similar occurrences.

Hostile cyber intrusions could severely impair our operations, lead to the disclosure of confidential information and damage our reputation.

We own assets deemed as critical infrastructure, the operation of which is dependent on information technology systems. Further, the computer systems that run our facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. bulk power system or our operations could view our computer systems, software or networks as targets for cyber attack. In addition, our business requires that we collect and maintain sensitive customer data, as well as confidential employee and shareholder information, which is subject to electronic theft or loss.

A successful cyber attack on the systems that control our generation, transmission, distribution or other assets could severely disrupt business operations, preventing us from serving customers or collecting revenues. The breach of certain business systems could affect our ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. In addition, the misappropriation, corruption or loss of personally identifiable information and other confidential data could lead to significant breach notification expenses and mitigation expenses such as credit monitoring. We maintain property and casualty insurance that may cover certain physical damage or third-party injuries caused by potential cyber security incidents. However, other damage and claims arising from such incidents may not be covered or may exceed the amount of any insurance available. For these reasons, a significant cyber incident could reduce future net income and cash flows and impact financial condition.

In an effort to reduce the likelihood and severity of cyber intrusions, we have a comprehensive cyber security program designed to protect and preserve the confidentiality, integrity and availability of data and systems. In addition, we are subject to mandatory cyber security regulatory requirements. However, cyber threats continue to evolve and adapt, and, as a result, there is a risk that we could experience a successful cyber attack despite our current security posture and regulatory compliance efforts.

If we are unable to access capital markets on reasonable terms, it could reduce future net income and cash flows and impact financial condition.

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Volatility and reduced liquidity in the financial markets could affect our ability to raise capital and fund our capital needs, including construction costs and refinancing maturing indebtedness. In addition, if capital is available only on less than reasonable terms or to borrowers whose creditworthiness is better than ours, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could reduce future net income and cash flows and impact financial condition.

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses.

The credit ratings agencies periodically review our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to us and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. In periods of market turmoil, access to capital is difficult for all borrowers. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and could reduce future net income and cash flows and impact financial condition.

Our power trading business relies on our investment grade ratings. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If our ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

Our operating results may fluctuate on a seasonal or quarterly basis and with general economic and weather conditions.

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition. Conversely, unusually extreme weather conditions could increase our results of operations in a manner that would not likely be sustainable.

Further, deteriorating economic conditions generally result in reduced consumption by our customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, our overall operating results in the future may fluctuate on the basis of prevailing economic conditions.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations.

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations.

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades, construction of additional generation units and transmission facilities as well as other initiatives. We are exposed to the risk of substantial price increases in the costs of materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

Changes in commodity prices and the costs of transport may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance.

We are exposed to changes in the price and availability of coal and the price and availability to transport coal. We have existing contracts of varying durations for the supply of coal, but as these contracts end or otherwise are not honored, we may not be able to purchase coal on terms as favorable as the current contracts. Similarly, we are exposed to changes in the price and availability of emission allowances. We use emission allowances based on the amount of coal we use as fuel and the reductions achieved through emission controls and other measures. As long as current environmental programs remain in effect, we have sufficient emission allowances to cover the majority of our projected needs for the next two years and beyond. If the United States Environmental Protection Agency (the "Federal EPA") is able to create a replacement rule to reduce interstate transport, and it is acceptable by the courts, additional costs may be incurred either to acquire additional allowances or to achieve further reductions in emissions. If we need to obtain allowances under a replacement rule, those purchases may not be on as favorable terms as those under the current environmental programs. Our risks relative to the price and availability to transport coal include the volatility of the price of diesel which is the primary fuel used in transporting coal by barge.

We also have plans to convert a generating unit from coal to natural gas-fired facilities. This would expose us to market prices of natural gas. Historically, natural gas prices have tended to be more volatile than prices for other fuel sources. Recently however, the availability of natural gas from shale production has lessened price volatility. Our ability to make off-system sales at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices relative to our off-system sales prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants. We expect the availability of shale natural gas and issues related to its accessibility will have a long-term material effect on the price and volatility of natural gas.

Prices for coal, natural gas and emission allowances have shown material upward and downward swings in the past. Changes in the cost of coal, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value our trading and marketing transactions, and those differences may be material. As a result, our financial results may be diminished in the future as those transactions are marked to market.

We are subject to physical and financial risks associated with climate change.

There is a growing consensus on the evidence of global climate change. Climate change creates physical and financial risk. Physical risks from climate change include an increase in sea level and changes in weather conditions, such as changes in precipitation and extreme weather events. Our customers' energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions are affected by climate change, customers' energy use could increase or decrease depending on the duration and magnitude of the changes.

Increased energy use due to weather changes may require us to invest in additional generating assets, transmission and other infrastructure to serve increased load. Decreased energy use due to weather changes may affect our financial condition, through decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stress, including service interruptions. Weather conditions outside of our service territory could also have an impact on our revenues. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions creating high energy demand on our own and/or other systems may raise electricity prices as we buy short-term energy to serve our own system, which would increase the cost of energy we provide to our customers.

Severe weather impacts our service territories, primarily when thunderstorms, tornadoes, hurricanes and snow or ice storms occur. To the extent the frequency of extreme weather events increases, this could increase our cost of providing service. Changes in precipitation resulting in droughts or water shortages could adversely affect our operations, principally our fossil generating units. A negative impact to water supplies due to long-term drought conditions could adversely impact our ability to provide electricity to customers, as well as increase the price they pay for energy. We may not recover all costs related to mitigating these physical and financial risks.

To the extent climate change impacts a region's economic health, it may also impact our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods and services, has an impact on the economic health of our communities.

We cannot predict the outcome of the legal proceedings relating to our business activities.

We are involved in legal proceedings, claims and litigation arising out of our business operations. Adverse outcomes in these proceedings could require significant expenditures that could have a material adverse effect on our results of operations.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Our costs of compliance with existing environmental laws are significant.

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. The electricity we generate is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generation plants are subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities and could cause us to retire generating capacity prior to the end of its estimated useful life. These expenditures have been significant in the past and we expect that they will continue to be significant in order to comply with the current and proposed regulations. Costs of compliance with environmental regulations could reduce future net income and impact financial condition, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed and additional substances become regulated. If we retire generation plants prior to the end of their estimated useful life, there can be no assurance that we will recover the remaining costs associated with such plants. We typically recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates in regulated jurisdictions. Failure to recover these costs could reduce our future net income and cash flows and possibly harm our financial condition.

Regulation of CO_2 emissions, either through legislation or by the Federal EPA, could materially increase costs to us and our customers or cause some of our electric generating units to be uneconomical to operate or maintain.

In June 2014, Federal EPA issued standards for modified and reconstructed units, and a guideline for the development of state implementation plans that would reduce carbon emissions from existing utility units. Federal EPA is to finalize those standards by June 2015, and to require states to submit implementation plans no later than June 2016.

If CO_2 and other emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. We typically recover costs of complying with new requirements such as the potential CO_2 and other greenhouse gases emission standards from customers through regulated rates in regulated jurisdictions. For our sales of energy based on market rate authority, however, there is no such recovery mechanism. Failure to recover these costs, should they arise, could reduce our future net income and cash flows and possibly harm our financial condition.

Courts adjudicating nuisance and other similar claims against us may order us to pay damages or to limit or reduce our CO_2 emissions.

In the past, there have been several cases seeking damages based on allegations of federal and state common law nuisance in which we or our affiliates, among others, were defendants. In general, the actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance due to impacts of global warming and climate change. The plaintiffs in these actions generally seek recovery of damages and other relief. If the pending or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required and we might be required to limit or reduce CO_2 emissions. Such remedies could require us to purchase power from third parties to fulfill our commitments to supply power to our customers. This could have a material impact on our costs. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. While management believes such costs should be recoverable from customers as costs of doing business in our jurisdictions where generation rates are set on a cost of service basis, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

Changes in technology and regulatory policies may cause our generating facilities to be less competitive.

We primarily generate electricity at large central facilities. This method results in economies of scale and lower costs than newer technologies such as fuel cells, microturbines, windmills and photovoltaic solar cells. It is possible that advances in technologies or changes in regulatory policies will reduce costs of new technology to levels that are equal to or below that of most central station electricity production, which could have a material adverse effect on our results of operations.

Our profitability is impacted by our continued authorization to sell power at market-based rates.

FERC has granted us authority to sell electricity at market-based rates. FERC reserves the right to revoke or revise this market-based rate authority if it subsequently determines that we or our affiliates can exercise market power in transmission or generation, create barriers to entry or engage in abusive affiliate transactions. We must file a market power update every three years to show that we continue to meet FERC's standards with respect to generation market power and other criteria used to evaluate whether entities qualify for market-based rates. The loss of market-based rate authority by any of these entities could have a material adverse effect on our results of operations.

Our revenues and results of operations from selling power are subject to market risks that are beyond our control.

We sell power from our generation facilities into the spot market and other competitive power markets on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, the rate of return on our capital investments is not determined through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices can fluctuate substantially over relatively short periods of time. Trading margins may erode as markets mature and there may be diminished opportunities for gain should volatility decline. In addition, the FERC, which has jurisdiction over wholesale power rates, as well as RTOs that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Power supply and other similar agreements entered into during extreme market conditions may subsequently be held to be unenforceable by a reviewing court or the FERC. Fuel and emissions prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel and/or emissions costs. These factors could reduce our margins and therefore diminish our revenues and results of operations. Volatility in market prices for fuel and power may result from:

- Weather conditions, including storms.
- Economic conditions.
- Outages of major generation or transmission facilities.
- Seasonality.
- Power usage.
- Illiquid markets.
- Transmission or transportation constraints or inefficiencies.
- Availability of competitively priced alternative energy sources.
- Demand for energy commodities.
- Natural gas, crude oil and refined products and coal production levels.
- Natural disasters, wars, embargoes and other catastrophic events.
- Federal, state and foreign energy and environmental regulation and legislation and/or incentives.

Commodity trading and marketing activities are subject to inherent risks which can be reduced and controlled but not eliminated.

We attempt to manage the exposure of our power trading activities by establishing and enforcing risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate the risks associated with these activities. As a result, we cannot predict the impact that our energy trading and risk management decisions may have on our business, operating results or financial position.

We routinely have open trading positions in the market, within guidelines we set, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish our financial results and financial position.

Our power trading risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

We may not successfully manage the uncertainty involved with our power trading (including coal, natural gas and emission allowances trading and power marketing).

Our power trading activities also expose us to risks of commodity price movements. To the extent that our power trading does not hedge the price risk associated with the generation it owns, or controls, through long-term power purchase agreements, we would be exposed to the risk of rising and falling spot market prices.

For example, the use of new technologies to recover natural gas from shale deposits has increased natural gas supply and reserves, placing further downward pressure on natural gas prices and has reduced the need for our coal-fired generation. Further, in the event that alternative generation resources, such as wind and solar, are mandated or otherwise subsidized or encouraged through climate legislation or regulation and added to the available generation supply, such resources could displace a higher marginal cost fossil plant, which could reduce the price at which market participants sell their electricity. This occurrence could then reduce the market price at which all generators in that region would be able to sell their output. These events could adversely affect our financial condition, results of operations and cash flows, and could also result in an impairment of certain long-lived assets.

In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of the financial contracts change in a manner we do not anticipate, it could harm our financial position or reduce the financial contribution of our trading operations.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations.

We are exposed to the risk that counterparties that owe us money or power could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by a counterparty may be greater than the estimates predict.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver our wholesale electric power to the purchasers of our power.

We depend on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver our wholesale power. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

Financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations.

In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act was signed into law (the "Dodd-Frank Act"). The federal legislation was enacted to reform financial markets and significantly alter how over-the-counter ("OTC") derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including: (a) imposing pervasive regulation by the Commodity Futures Trading Commission (the "CFTC") on dealers and traders who hold significant positions in swaps, (b) requiring certain standardized OTC derivatives to be traded on registered exchanges as directed by CFTC, (c) imposing new and potentially higher capital and margin requirements on swap dealers and traders who hold significant positions in swaps and (d) increasing the monitoring and compliance obligations of parties who engage in swaps, including new recordkeeping and reporting requirements with governmental entities. The CFTC has issued regulations exempting certain end users of energy commodities from being required to clear OTC derivatives, provided that they (a) are using the swaps to hedge or mitigate commercial risk and (b) satisfy certain other requirements. To the extent we meet such requirements, the end user exemption could reduce the effect of the law's clearing requirements on our hedging activity. Pursuant to authority granted under the Dodd-Frank Act, the CFTC has also issued rules that, among other things, further define the OTC derivative products and entities subject to additional regulatory oversight, which recently became effective. These requirements could subject us to additional regulatory oversight related to our OTC derivative transactions, cause our OTC derivative transactions to be more costly and have an impact on financial condition due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to manage.

RATIO OF EARNINGS TO FIXED CHARGES

The Ratio of Earnings to Fixed Charges for each of the periods indicated is as follows:

Twelve Months Period Ended	Ratio
December 31, 2011	2.61
December 31, 2012	2.46
December 31, 2013	1.33
March 31, 2014	2.00

The Ratio of Earning to Fixed Charges for the three months ended March 31, 2014 was 6.09. For the purposes of calculating the Ratio of Earnings to Fixed Charges, “earnings” represents income before income taxes, extraordinary items, and cumulative effect of accounting changes, plus fixed charges. “Fixed charges” consist of interest expense, amortization of debt issuance costs, and the portion of operating rental expense which management believes is representative of the interest within rental expense.

INDEPENDENT AUDITORS

The financial statements of Kentucky Power Company as of December 31, 2013 and 2012, and for each of the three years in the period ended December 31, 2013, included in this Official Statement have been audited by Deloitte & Touche LLP, independent auditors, as stated in their report appearing herein.

Kentucky Power Company

2013 Annual Report

Audited Financial Statements

AMERICAN ELECTRIC POWER

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
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.
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.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
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.
CWIP	Construction Work in Progress.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IAA	AEP System Interim Allowance Agreement.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo which defined the sharing of costs and benefits associated with their respective generating plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.

Term	Meaning
OATT	Open Access Transmission Tariff.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PCA	Power Coordination Agreement.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utility Commission of Ohio.
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. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, 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.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying financial statements of Kentucky Power Company (the "Company"), which comprise the balance sheets as of December 31, 2013 and 2012, and the related statements of income, comprehensive income (loss), changes in common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2013, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

Management is responsible for the preparation and fair presentation of these financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2013 and 2012, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2013 in accordance with accounting principles generally accepted in the United States of America.

Emphasis of Matter

The financial statements give retroactive effect to the transfer of a fifty percent interest in Units 1 and 2 of the Mitchell Plant to the Company on December 31, 2013, which has been accounted for at historical cost as a transfer between entities under common control as described in Note 1 to the financial statements. Our opinion is not modified with respect to this matter.

Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31, 2013	2012	2011
REVENUES			
Electric Generation, Transmission and Distribution	$ 721,840	$ 753,095	$ 847,867
Sales to AEP Affiliates	103,731	70,776	104,682
Other Revenues	684	546	494
TOTAL REVENUES	826,255	824,417	953,043
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	200,139	219,328	336,164
Purchased Electricity for Resale	11,003	11,319	23,924
Purchased Electricity from AEP Affiliates	269,088	223,649	210,299
Other Operation	75,038	75,410	77,804
Maintenance	66,977	63,125	67,094
Asset Impairments and Other Related Charges	32,847	-	-
Depreciation and Amortization	91,692	87,995	86,498
Taxes Other Than Income Taxes	20,272	19,659	18,567
TOTAL EXPENSES	767,056	700,485	820,350
OPERATING INCOME	59,199	123,932	132,693
Other Income (Expense):			
Interest Income	231	351	2,324
Allowance for Equity Funds Used During Construction	1,367	1,574	1,229
Interest Expense	(44,509)	(49,375)	(51,101)
INCOME BEFORE INCOME TAX EXPENSE	16,288	76,482	85,145
Income Tax Expense	7,382	23,507	31,169
NET INCOME	$ 8,906	$ 52,975	$ 53,976

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

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31,		
	2013	**2012**	**2011**
Net Income	$ 8,906	$ 52,975	$ 53,976
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $113, $117 and $94 in 2013, 2012 and 2011, Respectively	210	216	(174)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $755, $687 and $540 in 2013, 2012 and 2011, Respectively	1,402	1,275	1,002
Pension and OPEB Funded Status, Net of Tax of $4,168, $1,801 and $400 in 2013, 2012 and 2011, Respectively	7,741	3,345	(743)
TOTAL OTHER COMPREHENSIVE INCOME	9,353	4,836	85
TOTAL COMPREHENSIVE INCOME	$ 18,259	$ 57,811	$ 54,061

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2010	$ 50,450	$ 478,022	$ 157,467	$ (24,915)	$ 661,024
Capital Contribution from Parent		41,972			41,972
Common Stock Dividends			(39,602)		(39,602)
Net Income			53,976		53,976
Other Comprehensive Income				85	85
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2011	50,450	519,994	171,841	(24,830)	717,455
Capital Contribution from Parent		11,542			11,542
Common Stock Dividends			(33,997)		(33,997)
Net Income			52,975		52,975
Other Comprehensive Income				4,836	4,836
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2012	50,450	531,536	190,819	(19,994)	752,811
Capital Contribution from Parent		83,112			83,112
Common Stock Dividends			(20,034)		(20,034)
Net Income			8,906		8,906
Other Comprehensive Income				9,353	9,353
Pension and OPEB Adjustment Related to Mitchell Plant				5,221	5,221
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2013 and 2012
(in thousands)

	December 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 743	$ 1,482
Accounts Receivable:		
Customers	17,889	25,826
Affiliated Companies	9,781	53,285
Accrued Unbilled Revenues	857	4,472
Miscellaneous	75	249
Allowance for Uncollectible Accounts	(78)	(164)
Total Accounts Receivable	28,524	83,668
Fuel	92,313	98,717
Materials and Supplies	43,940	38,306
Risk Management Assets	4,356	6,175
Accrued Tax Benefits	5,249	5,186
Prepayments and Other Current Assets	3,284	6,791
TOTAL CURRENT ASSETS	178,409	240,325
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,052,757	1,438,999
Transmission	507,844	495,981
Distribution	693,481	652,615
Other Property, Plant and Equipment (Including Plant to be Retired)	480,759	65,150
Construction Work in Progress	128,599	87,924
Total Property, Plant and Equipment	2,863,440	2,740,669
Accumulated Depreciation and Amortization	943,889	884,016
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,919,551	1,856,653
OTHER NONCURRENT ASSETS		
Regulatory Assets	216,360	213,734
Long-term Risk Management Assets	3,484	6,882
Employee Benefits and Pension Assets	11,446	-
Deferred Charges and Other Noncurrent Assets	20,207	54,986
TOTAL OTHER NONCURRENT ASSETS	251,497	275,602
TOTAL ASSETS	$ 2,349,457	$ 2,372,580

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
December 31, 2013 and 2012

	December 31, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 8,564	$ 13,359
Accounts Payable:		
General	21,619	75,444
Affiliated Companies	39,171	56,256
Long-term Debt Due Within One Year – Nonaffiliated	-	250,000
Risk Management Liabilities	1,828	3,320
Customer Deposits	25,211	23,485
Deferred Income Taxes	6,486	2,376
Accrued Taxes	20,801	16,650
Accrued Interest	6,678	12,002
Regulatory Liability for Over-Recovered Fuel Costs	2,851	7,928
Other Current Liabilities	19,411	29,480
TOTAL CURRENT LIABILITIES	152,620	490,300
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	729,389	529,195
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,105	3,700
Deferred Income Taxes	549,672	503,147
Regulatory Liabilities and Deferred Investment Tax Credits	22,926	26,159
Employee Benefits and Pension Obligations	6,041	32,387
Deferred Credits and Other Noncurrent Liabilities	27,335	14,881
TOTAL NONCURRENT LIABILITIES	1,357,468	1,129,469
TOTAL LIABILITIES	1,510,088	1,619,769
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	614,648	531,536
Retained Earnings	179,691	190,819
Accumulated Other Comprehensive Income (Loss)	(5,420)	(19,994)
TOTAL COMMON SHAREHOLDER'S EQUITY	839,369	752,811
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,349,457	$ 2,372,580

See Notes to Financial Statements beginning on page 10.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012 and 2011
(in thousands)

	Years Ended December 31, 2013	2012	2011
OPERATING ACTIVITIES			
Net Income	$ 8,906	$ 52,975	$ 53,976
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	91,692	87,995	86,498
Deferred Income Taxes	12,440	10,168	33,153
Asset Impairments and Other Related Charges	32,847	-	-
Allowance for Equity Funds Used During Construction	(1,367)	(1,574)	(1,229)
Mark-to-Market of Risk Management Contracts	2,357	2,510	(220)
Pension Contributions to Qualified Plan Trust	-	(5,547)	(18,239)
Fuel Over/Under-Recovery, Net	(5,078)	4,790	2,274
Change in Other Noncurrent Assets	7,334	(13,338)	(10,711)
Change in Other Noncurrent Liabilities	(2,953)	697	2,927
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	55,144	(7,523)	14,707
Fuel, Materials and Supplies	3,130	(55,120)	(3,618)
Accounts Payable	(68,480)	3,429	(9,748)
Accrued Taxes, Net	4,013	(11,400)	(2,152)
Accrued Interest	(5,324)	(545)	131
Other Current Assets	3,817	607	730
Other Current Liabilities	(9,186)	2,974	4,363
Net Cash Flows from Operating Activities	129,292	71,098	152,842
INVESTING ACTIVITIES			
Construction Expenditures	(141,832)	(130,964)	(83,902)
Change in Advances to Affiliates, Net	-	70,332	(3,272)
Acquisitions of Assets	(563)	(419)	(1,289)
Proceeds from Sales of Assets	5,566	1,032	439
Net Cash Flows Used for Investing Activities	(136,829)	(60,019)	(88,024)
FINANCING ACTIVITIES			
Capital Contribution from Parent	83,112	11,542	41,972
Issuance of Long-term Debt – Nonaffiliated	199,700	-	-
Change in Advances from Affiliates, Net	(4,795)	13,359	-
Retirement of Long-term Debt – Nonaffiliated	(250,000)	-	(65,000)
Principal Payments for Capital Lease Obligations	(1,440)	(1,503)	(1,742)
Dividends Paid on Common Stock	(20,034)	(33,997)	(39,602)
Other Financing Activities	255	224	51
Net Cash Flows from (Used for) Financing Activities	6,798	(10,375)	(64,321)
Net Increase (Decrease) in Cash and Cash Equivalents	(739)	704	497
Cash and Cash Equivalents at Beginning of Period	1,482	778	281
Cash and Cash Equivalents at End of Period	$ 743	$ 1,482	$ 778
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 48,602	$ 48,740	$ 50,429
Net Cash Paid for Income Taxes	6,100	23,089	7,785
Noncash Acquisitions Under Capital Leases	3,448	2,136	621
Construction Expenditures Included in Current Liabilities as of December 31,	7,253	28,565	13,735

See Notes to Financial Statements beginning on page 10.

INDEX OF NOTES TO FINANCIAL STATEMENTS

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 172,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

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

Effective January 1, 2014, the FERC approved a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo will be individually responsible for planning their respective capacity obligations and there will be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

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

Effective January 1, 2014, AEPSC conducts power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other risk management activities on behalf of APCo, I&M and KPCo. Power and natural gas risk management activities are allocated based on the three member companies' respective equity positions and the SIA. KPCo shared in coal 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, natural gas and coal. The power, natural gas and coal contracts include physical transactions, OTC 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. For contracts entered and settled prior to January 1, 2014, power and natural gas risk management activities were allocated based on the Interconnection Agreement and the SIA. For contracts entered prior to January 1, 2014 and settled after January 1, 2014, power and natural gas risk management activities are allocated based on frozen MLR ratios as of December 31, 2013. KPCo shared in the revenues and expenses associated with these risk management activities with the other AEP East Companies, PSO and SWEPCo.

Under a unit power agreement with AEGCo, an affiliated company that was 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 natural gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of 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.

Prior to January 1, 2014, the Interconnection Agreement permitted the AEP East Companies to pool their generation assets on a cost basis. It established 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 were compensated for their costs of energy delivered and charged for energy received. The capacity reserve relationship of the Interconnection Agreement members changed as generating assets were added, retired or sold and relative peak demand changed. The Interconnection Agreement calculated 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 was the MLR, which determined each member's percentage share of revenues and costs.

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.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved the corporate separation of OPCo's generation assets and generation liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. Also on December 31, 2013, AGR subsequently transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Significant Accounting Issues

AGR's transfer of a one-half ownership in the Mitchell Plant to KPCo at net book value qualifies as an acquisition of a business under common control. Pursuant to "Business Combinations" accounting guidance, KPCo retrospectively adjusted its financial statements as if the transfer had occurred at the beginning of the earliest period presented.

None of the OPCo regulatory assets and regulatory liabilities were transferred to KPCo. As previously approved by the PUCO, these regulatory assets and liabilities will be recovered/refunded primarily through OPCo non-bypassable riders.

Substantially all of the current income tax receivables and payables related to OPCo's generation activities prior to December 31, 2013 will remain on OPCo's balance sheet. These current income tax receivables and payables are the responsibility of OPCo. Deferred tax assets and liabilities related to KPCo's acquired share of the Mitchell Plant were transferred to KPCo based upon the Mitchell Plant's related asset and liability values. Following these transfers, KPCo adjusted its deferred tax balances and related regulatory assets to reflect its respective deferred state tax rates.

Long-term Debt

On December 31, 2013, KPCo was assigned $200 million of Long-term Debt – Nonaffiliated from AGR related to a term credit facility.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

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

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

In addition, the FERC regulates the SIA, the System Transmission Integration Agreement and the Transmission Agreement, all of which are still active and allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement. In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated. In December 2013, the FERC issued orders approving the creation of a Power Coordination Agreement (PCA), effective January 1, 2014. Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent.

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 in conformity with accounting principles generally accepted in the United States of America (GAAP) 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 include temporary cash investments with original maturities of three months or less.

Inventory

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

Accounts Receivable

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

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

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

Allowance for Uncollectible Accounts

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

Concentrations of Credit Risk and Significant Customers

KPCo does not have any significant customers that comprise 10% or more of its operating revenues as of December 31, 2013.

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. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation 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 Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and KPCo's revenue optimization strategy for operations. 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 original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. 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 held-for-sale 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. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Advances to/from Affiliates, 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 amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with established risk management policies as approved by the Finance Committee of AEP's Board of Directors. The AEP System's market risk oversight staff independently monitors risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of AEPSC's Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer.

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

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 Fuel and Other Consumables Used for Electric Generation expense 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 current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current 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 FAC under-recovery is no longer probable of recovery, 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.

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 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 Purchased Electricity for Resale 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 Purchased Electricity for Resale 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 Purchased Electricity for Resale 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 power, coal and natural gas 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 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). Unrealized MTM gains and losses are included on the balance sheets as Risk Management Assets or Liabilities as appropriate.

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 9.

Maintenance

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

Income Taxes and Investment Tax Credits

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

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

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

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

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 Interest 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.

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	30.0 %
Fixed Income	55.0 %
Other Investments	15.0 %

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 and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, the investment policies do not preclude the benefit trust funds from receiving contributions in the form of AEP securities, provided that the AEP securities acquired by each plan may not exceed the limitations imposed by law. 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, which are publicly traded real estate securities.

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

AEP participates in a securities lending program with BNY Mellon to provide incremental income on idle assets and to provide income to offset custody fees and other administrative expenses. AEP lends securities to borrowers approved by BNY Mellon in exchange for 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 trust is to minimize taxes paid on the asset growth in the trust. Earnings on plan assets are tax-deferred within the TOLI contract and can be tax-free if held until claims are paid. Life insurance proceeds remain in the trust and are used to fund future retiree medical benefit liabilities. With consideration to other investments held in the trust, the cash value of the TOLI contracts is invested in two diversified funds. A portion is invested in a commingled fund with underlying investments in stocks that are actively traded on major international equity exchanges. The other portion of the TOLI cash value is invested in a diversified, commingled fixed income fund with underlying investments in government bonds, corporate bonds and asset-backed securities.

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

Comprehensive Income (Loss)

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

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Subsequent Events

Management reviewed subsequent events through February 25, 2014, the date that KPCo's 2013 annual report was issued.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the year ended December 31, 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges		Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in thousands)		
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ 1,275	$ (20,860)	$ (19,994)
Change in Fair Value Recognized in AOCI	152	-	-	7,741	7,893
Amounts Reclassified from AOCI	(2)	60	1,402	-	1,460
Net Current Period Other Comprehensive Income	150	60	1,402	7,741	9,353
Pension and OPEB Adjustment Related to Mitchell Plant	-	-	-	5,221	5,221
Balance in AOCI as of December 31, 2013	$ 23	$ (222)	$ 2,677	$ (7,898)	$ (5,420)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the year ended December 31, 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Year Ended December 31, 2013

Gains and Losses on Cash Flow Hedges	**Amount of (Gain) Loss Reclassified from AOCI (in thousands)**
Commodity:	
Electric Generation, Transmission and Distribution Revenues	$ (64)
Purchased Electricity for Resale	84
Other Operation Expense	(8)
Maintenance Expense	(5)
Property, Plant and Equipment	(11)
Subtotal - Commodity	(4)
Interest Rate and Foreign Currency:	
Interest Expense	93
Subtotal - Interest Rate and Foreign Currency	93
Reclassifications from AOCI, before Income Tax (Expense) Credit	89
Income Tax (Expense) Credit	31
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	58
Pension and OPEB	
Amortization of Prior Service Cost (Credit)	(364)
Amortization of Actuarial (Gains)/Losses	2,521
Change in Funded Status	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	2,157
Income Tax (Expense) Credit	755
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	1,402
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 1,460

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges 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:			
Electric Generation, Transmission and Distribution Revenues	(16)	-	(16)
Purchased Electricity for Resale	427	-	427
Other Operation Expense	(5)	-	(5)
Maintenance Expense	-	-	-
Interest Expense	-	60	60
Property, Plant and Equipment	(4)	-	(4)
Regulatory Assets (a)	-	-	-
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (409)

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

	Commodity	Interest Rate	Total
		(in thousands)	
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:			
Electric Generation, Transmission and Distribution Revenues	205	-	205
Purchased Electricity for Resale	51	-	51
Other Operation Expense	(32)	-	(32)
Maintenance Expense	(37)	-	(37)
Interest Expense	-	61	61
Property, Plant and Equipment	(47)	-	(47)
Regulatory Assets (a)	56	-	56
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (283)	$ (342)	$ (625)

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

3. <u>RATE MATTERS</u>

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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of December 31, 2013, the net book value of Big Sandy Plant, Unit 2 was $249 million, before cost of removal, including materials and supplies inventory and CWIP. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace a portion of the capacity from Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In November 2013, the KPSC denied the Attorney General's petition for rehearing. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase included cost recovery of the proposed transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order in the plant transfer case which modified and approved a settlement agreement that included the approval of the proposed transfer of the one-half interest in the Mitchell Plant to KPCo. The modified and approved settlement agreement also included KPCo's agreement to withdraw this base rate case request and file a base case proceeding no later than December 2014 with its current base rates to remain in effect until at least May 2015. In November 2013, KPCo withdrew this base rate request and the withdrawal was approved by the KPSC.

<u>FERC Rate Matters</u>

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 and to transfer at net book value AGR's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each), to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR, and the

Mitchell Plant assets to APCo and KPCo. In January 2014, the FERC dismissed an Industry Energy Users-Ohio petition for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AGR. In December 2013, the transfer of the Mitchell Plant to KPCo was completed. See the "Plant Transfer" section of Rate Matters.

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

In December 2013, the FERC issued orders approving the creation of a Power Coordination Agreement (PCA), effective January 1, 2014, conditioned upon certain compliance filings which were filed with the FERC in January 2014. The PCA was established among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, KPCo would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by orders from the Virginia SCC and the KPSC related to the proposed asset transfers and to position the company for the final stages of corporate separation. In December 2013, the FERC issued an order approving these additional filings. See the "Plant Transfers" section of Rate Matters.

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.

4. EFFECTS OF REGULATION

Regulated Generating Unit to be Retired Before or During 2016

The following regulated generating unit is probable of abandonment. Accordingly, CWIP and Plant in Service has been reclassified as Other Property, Plant and Equipment on the balance sheet as of December 31, 2013. The following table summarizes the plant investment and cost of removal, currently being recovered, for the generating unit as of December 31, 2013.

Plant Name and Unit	Gross Investment	Accumulated Depreciation	Net Investment	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
	(in thousands)					
Big Sandy Plant, Unit 2	$ 423,687	$ 180,192	$ 243,495	$ 47,181	2015	27 years
Total	$ 423,687	$ 180,192	$ 243,495	$ 47,181		

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	**December 31, 2013**	**December 31, 2012**	**Remaining Recovery Period**
	(in thousands)		
Noncurrent Regulatory Assets			
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	$ 12,146	
Mountaineer Carbon Capture and Storage Commercial Scale Facility	-	873	
Total Regulatory Assets Not Yet Being Recovered	12,146	13,019	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Other Regulatory Assets Being Recovered	1,422	1,668	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	154,603	127,489	22 years
Pension and OPEB Funded Status	32,458	52,048	11 years
Storm Related Costs	7,048	11,746	2 years
Postemployment Benefits	4,530	5,230	5 years
Medicare Subsidy	2,383	-	11 years
Peak Demand Reduction/Energy Efficiency	914	1,589	1 year
Other Regulatory Assets Being Recovered	856	945	various
Total Regulatory Assets Being Recovered	204,214	200,715	
Total Noncurrent Regulatory Assets	$ 216,360	$ 213,734	

Regulatory Liabilities:	**December 31, 2013**	**December 31, 2012**	**Remaining Refund Period**
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ 2,851	$ 7,928	1 year
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	$ 19,231	$ 21,066	(a)
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	3,259	4,288	4 years
Deferred Investment Tax Credits	126	356	7 years
Other Regulatory Liabilities Being Paid	310	449	various
Total Regulatory Liabilities Being Paid	22,926	26,159	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 22,926	$ 26,159	

(a) Relieved as removal costs are incurred.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

COMMITMENTS

Construction and Commitments

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

The following table summarizes KPCo's actual contractual commitments as of December 31, 2013:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in thousands)		
Fuel Purchase Contracts (a)	$ 198,192	$ 246,401	$ 232,240	$ 348,360	$ 1,025,193
Energy and Capacity Purchase Contracts	35,144	70,156	69,993	139,846	315,139
Construction Contracts for Capital Assets (b)	1,786	-	-	-	1,786
Total	$ 235,122	$ 316,557	$ 302,233	$ 488,206	$ 1,342,118

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

GUARANTEES

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

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, 2013, 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 12 for disclosure of lease residual value guarantees.

CONTINGENCIES

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an electric utility, subject to various deductibles. 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.

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. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court's dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme Court.

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. 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 filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

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, 2013, 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.

6. IMPAIRMENT

2013

Big Sandy Plant, Unit 2 FGD Project

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million in Asset Impairments and Other Related Charges on the statement of income primarily related to the Big Sandy Plant, Unit 2 FGD project. See the "Plant Transfer" section of Note 3.

7. BENEFIT PLANS

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "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 an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2013**	**2012**	**2013**	**2012**
Discount Rate	4.70 %	3.95 %	4.70 %	3.95 %
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 2013, 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 4.5%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	5.05 %	3.95 %	4.75 %	5.25 %
Expected Return on Plan Assets	6.50 %	7.25 %	7.75 %	7.00 %	7.25 %	7.50 %
Rate of Compensation Increase	4.50 %	4.50 %	4.50 %	NA	NA	NA

NA Not applicable.

The expected return on plan assets for 2013 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

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

Health Care Trend Rates	2013	2012
Initial	6.75 %	7.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2020

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

	1% Increase	1% Decrease
	(in thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 164	$ (108)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	2,101	(1,710)

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, 2013, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2013 and 2012

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	
	2013	2012	2013	2012
Change in Benefit Obligation	(in thousands)			
Benefit Obligation as of January 1,	$ 183,994	$ 170,910	$ 66,513	$ 83,480
Service Cost	1,763	2,231	750	1,636
Interest Cost	7,074	7,762	2,491	3,821
Actuarial (Gain) Loss	(13,578)	15,617	(15,950)	437
Plan Amendment Prior Service Credit	-	-	-	(19,043)
Benefit Payments	(9,821)	(12,526)	(4,423)	(5,319)
Participant Contributions	-	-	1,198	1,194
Medicare Subsidy	-	-	227	307
Benefit Obligation as of December 31,	$ 169,432	$ 183,994	$ 50,806	$ 66,513
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 165,534	$ 151,450	$ 60,402	$ 55,418
Actual Gain on Plan Assets	13,865	21,063	5,748	5,752
Company Contributions	-	5,547	-	3,357
Participant Contributions	-	-	1,198	1,194
Benefit Payments	(9,821)	(12,526)	(4,423)	(5,319)
Fair Value of Plan Assets as of December 31,	$ 169,578	$ 165,534	$ 62,925	$ 60,402
Funded (Underfunded) Status as of December 31,	$ 146	$ (18,460)	$ 12,119	$ (6,111)

Amounts Recognized on the Balance Sheets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
	(in thousands)			
Employee Benefits and Pension Assets - Prepaid Benefit Costs	$ 146	$ -	$ 11,300	$ -
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	-	(18,460)	819	(6,111)
Funded (Underfunded) Status	$ 146	$ (18,460)	$ 12,119	$ (6,111)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
Components	(in thousands)			
Net Actuarial Loss	$ 51,587	$ 75,591	$ 12,769	$ 32,797
Prior Service Cost (Credit)	203	259	(24,069)	(26,468)
Recorded as				
Regulatory Assets	$ 42,089	$ 47,519	$ (9,631)	$ 4,529
Deferred Income Taxes	3,395	9,916	(584)	630
Net of Tax AOCI	6,306	18,415	(1,085)	1,170

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2013 and 2012 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2013	2012	2013	2012
Components	(in thousands)			
Actuarial (Gain) Loss During the Year	$ (17,611)	$ 5,845	$ (17,745)	$ (1,467)
Prior Service Credit	-	-	-	(19,043)
Amortization of Actuarial Loss	(6,393)	(5,225)	(2,283)	(2,117)
Amortization of Prior Service Credit (Cost)	(56)	(120)	2,399	676
Change for the Year	$ (24,060)	$ 500	$ (17,629)	$ (21,951)

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, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
	(in thousands)					
Equities:						
Domestic	$ 39,294	$ -	$ -	$ -	$ 39,294	23.2 %
International	18,522	-	-	-	18,522	10.9 %
Real Estate Investment Trusts	2,084	-	-	-	2,084	1.2 %
Common Collective Trust - International	-	352	-	-	352	0.2 %
Subtotal - Equities	59,900	352	-	-	60,252	35.5 %
Fixed Income:						
Common Collective Trust - Debt	-	933	-	-	933	0.5 %
United States Government and Agency Securities	-	13,922	-	-	13,922	8.2 %
Corporate Debt	-	57,592	-	-	57,592	34.0 %
Foreign Debt	-	12,372	-	-	12,372	7.3 %
State and Local Government	-	1,007	-	-	1,007	0.6 %
Other - Asset Backed	-	1,198	-	-	1,198	0.7 %
Subtotal - Fixed Income	-	87,024	-	-	87,024	51.3 %
Real Estate	-	-	8,575	-	8,575	5.0 %
Alternative Investments	-	-	11,865	-	11,865	7.0 %
Securities Lending	-	1,266	-	-	1,266	0.8 %
Securities Lending Collateral (a)	-	-	-	(1,627)	(1,627)	(0.9)%
Cash and Cash Equivalents	-	1,749	-	-	1,749	1.0 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	474	474	0.3 %
Total	$ 59,900	$ 90,391	$ 20,440	$ (1,153)	$ 169,578	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:

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2013	$ 7,740	$ 6,894	$ 14,634
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	1,197	532	1,729
Relating to Assets Sold During the Period	-	537	537
Purchases and Sales	(362)	3,902	3,540
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2013	$ 8,575	$ 11,865	$ 20,440

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 17,535	$ -	$ -	$ -	$ 17,535	27.9 %
International	22,796	-	-	-	22,796	36.2 %
Common Collective Trust - Global	-	544	-	-	544	0.9 %
Subtotal - Equities	40,331	544	-	-	40,875	65.0 %
Fixed Income:						
Common Collective Trust - Debt	-	3,255	-	-	3,255	5.2 %
United States Government and Agency Securities	-	2,093	-	-	2,093	3.3 %
Corporate Debt	-	4,078	-	-	4,078	6.5 %
Foreign Debt	-	796	-	-	796	1.2 %
State and Local Government	-	171	-	-	171	0.3 %
Other - Asset Backed	-	301	-	-	301	0.5 %
Subtotal - Fixed Income	-	10,694	-	-	10,694	17.0 %
Trust Owned Life Insurance:						
International Equities	-	490	-	-	490	0.8 %
United States Bonds	-	7,836	-	-	7,836	12.4 %
Cash and Cash Equivalents	2,527	325	-	-	2,852	4.5 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	178	178	0.3 %
Total	$ 42,858	$ 19,889	$ -	$ 178	$ 62,925	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, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 46,114	$ -	$ -	$ -	$ 46,114	27.9 %
International	17,512	-	-	-	17,512	10.5 %
Real Estate Investment Trusts	3,192	-	-	-	3,192	1.9 %
Common Collective Trust - International	-	153	-	-	153	0.1 %
Subtotal - Equities	66,818	153	-	-	66,971	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	1,118	-	-	1,118	0.7 %
United States Government and Agency Securities	-	25,215	-	-	25,215	15.2 %
Corporate Debt	-	43,539	-	-	43,539	26.3 %
Foreign Debt	-	7,002	-	-	7,002	4.2 %
State and Local Government	-	1,550	-	-	1,550	0.9 %
Other - Asset Backed	-	1,255	-	-	1,255	0.8 %
Subtotal - Fixed Income	-	79,679	-	-	79,679	48.1 %
Real Estate	-	-	7,740	-	7,740	4.7 %
Alternative Investments	-	-	6,894	-	6,894	4.2 %
Securities Lending	-	2,832	-	-	2,832	1.7 %
Securities Lending Collateral (a)	-	-	-	(3,203)	(3,203)	(1.9)%
Cash and Cash Equivalents	-	4,433	-	-	4,433	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	188	188	0.1 %
Total	$ 66,818	$ 87,097	$ 14,634	$ (3,015)	$ 165,534	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, 2012	$ 224	$ 5,757	$ 5,652	$ 11,633
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	1,049	355	1,404
Relating to Assets Sold During the Period	(79)	-	172	93
Purchases and Sales	(145)	934	715	1,504
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 7,740	$ 6,894	$ 14,634

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	$ 16,255	$ -	$ -	$ -	$ 16,255	26.9 %
International	19,436	-	-	-	19,436	32.2 %
Subtotal - Equities	35,691	-	-	-	35,691	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	2,795	-	-	2,795	4.6 %
United States Government and Agency Securities	-	3,166	-	-	3,166	5.2 %
Corporate Debt	-	5,964	-	-	5,964	9.9 %
Foreign Debt	-	1,008	-	-	1,008	1.7 %
State and Local Government	-	280	-	-	280	0.5 %
Other - Asset Backed	-	379	-	-	379	0.6 %
Subtotal - Fixed Income	-	13,592	-	-	13,592	22.5 %
Trust Owned Life Insurance:						
International Equities	-	1,985	-	-	1,985	3.3 %
United States Bonds	-	6,263	-	-	6,263	10.3 %
Cash and Cash Equivalents	2,391	439	-	-	2,830	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	41	41	0.1 %
Total	$ 38,082	$ 22,279	$ -	$ 41	$ 60,402	100.0 %

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

Determination of Pension Expense

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

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

Accumulated Benefit Obligation	December 31, 2013	December 31, 2012
	(in thousands)	
Qualified Pension Plan	$ 166,951	$ 180,892
Total	$ 166,951	$ 180,892

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 were as follows:

		Underfunded Pension Plans 2012
		(in thousands)
Projected Benefit Obligation	$	183,994
Accumulated Benefit Obligation	$	180,892
Fair Value of Plan Assets		165,534
Underfunded Accumulated Benefit Obligation	$	(15,358)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions and payments for the pension plans of $2.7 million during 2014. 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 were capped reducing exposure to future medical cost inflation. Effective for employees hired after December 2013, retiree medical coverage will not be provided. 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:

	Estimated Payments			
	Pension Plans		Other Postretirement Benefit Plans	
	(in thousands)			
2014	$	10,760	$	4,508
2015		11,334		4,820
2016		11,489		5,126
2017		11,946		5,385
2018		12,674		5,538
Years 2019 to 2023, in Total		64,896		30,389

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost (credit) for the years ended December 31, 2013, 2012 and 2011:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2013	2012	2011	2013	2012	2011
	(in thousands)					
Service Cost	$ 1,763	$ 2,231	$ 2,188	$ 750	$ 1,636	$ 1,513
Interest Cost	7,074	7,762	8,105	2,491	3,821	4,082
Expected Return on Plan Assets	(9,832)	(11,290)	(10,847)	(3,999)	(3,931)	(4,255)
Amortization of Prior Service Cost (Credit)	56	120	194	(2,399)	(676)	(46)
Amortization of Net Actuarial Loss	6,393	5,225	4,155	2,283	2,117	1,055
Net Periodic Benefit Cost (Credit)	5,454	4,048	3,795	(874)	2,967	2,349
Capitalized Portion	(2,372)	(1,388)	(1,139)	380	(1,018)	(705)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 3,082	$ 2,660	$ 2,656	$ (494)	$ 1,949	$ 1,644

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2014 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 4,335	$ 734
Prior Service Cost (Credit)	55	(2,443)
Total Estimated 2014 Amortization	$ 4,390	$ (1,709)
Expected to be Recorded as		
Regulatory Asset	$ 3,731	$ (1,595)
Deferred Income Taxes	231	(40)
Net of Tax AOCI	428	(74)
Total	$ 4,390	$ (1,709)

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan are 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for matching contributions totaled $2.3 million in 2013, $2.3 million in 2012 and $2.2 million in 2011.

8. BUSINESS SEGMENTS

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

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, 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 extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt 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, 2013 and 2012:

Notional Volume of Derivative Instruments

	Volume		
	December 31,		Unit of
Primary Risk Exposure	**2013**	**2012**	**Measure**
	(in thousands)		
Commodity:			
Power	10,071	18,838	MWhs
Coal	2	247	Tons
Natural Gas	509	2,018	MMBtus
Heating Oil and Gasoline	261	269	Gallons
Interest Rate	$ 2,615	$ 4,836	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, 2013 and 2012 balance sheets, KPCo netted $0 and $253 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $1 million and $2.2 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 KPCo's derivative activity on the balance sheets as of December 31, 2013 and 2012:

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 9,520	$ 85	$ -	$ 9,605	$ (5,249)	$ 4,356
Long-term Risk Management Assets	4,306	-	-	4,306	(822)	3,484
Total Assets	13,826	85	-	13,911	(6,071)	7,840
Current Risk Management Liabilities	7,583	65	-	7,648	(5,820)	1,828
Long-term Risk Management Liabilities	2,970	-	-	2,970	(865)	2,105
Total Liabilities	10,553	65	-	10,618	(6,685)	3,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,273	$ 20	$ -	$ 3,293	$ 614	$ 3,907

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 25,448	$ 72	$ -	$ 25,520	$ (19,345)	$ 6,175
Long-term Risk Management Assets	12,117	43	-	12,160	(5,278)	6,882
Total Assets	37,565	115	-	37,680	(24,623)	13,057
Current Risk Management Liabilities	23,806	239	-	24,045	(20,725)	3,320
Long-term Risk Management Liabilities	9,469	85	-	9,554	(5,854)	3,700
Total Liabilities	33,275	324	-	33,599	(26,579)	7,020
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,290	$ (209)	$ -	$ 4,081	$ 1,956	$ 6,037

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

The table below presents KPCo's activity of derivative risk management contracts for the years ended December 31, 2013, 2012 and 2011:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 1,483	$ (1,597)	$ 2,248
Sales to AEP Affiliates	-	-	31
Fuel and Other Consumables Used for Electric Generation	-	-	(3)
Regulatory Assets (a)	-	-	93
Regulatory Liabilities (a)	(1,029)	1,047	(1,158)
Total Gain (Loss) on Risk Management Contracts	$ 454	$ (550)	$ 1,211

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's statements of income depending on the relevant facts and circumstances. 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 Expense on KPCo's statements of income. During 2013, 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 (Loss) 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 Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's balance sheets, depending on the specific nature of the risk being hedged. During 2013, 2012 and 2011, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2013, 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 (Loss) on its balance sheets into Interest Expense on its statements of income in those periods in which hedged interest payments occur. During 2013, 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 (Loss) on KPCo's balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2013, 2012 and 2011, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During 2013, 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets and the reasons for changes in cash flow hedges, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's balance sheets as of December 31, 2013 and 2012 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 79	$ -	$ 79
Hedging Liabilities (a)	59	-	59
AOCI Loss Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

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

	Commodity	Interest Rate	Total
		(in thousands)	
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)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2013, 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 was 12 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (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, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 118	$ 432
Amount of Collateral KPCo Would Have Been Required to Post	565	741
Amount Attributable to RTO and ISO Activities	522	703

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, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 4,039	$ 9,907
Amount of Cash Collateral Posted	-	365
Additional Settlement Liability if Cross Default Provision is Triggered	3,817	6,041

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo's Long-term Debt as of December 31, 2013 and 2012 are summarized in the following table:

	December 31,			
	2013		2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 749,389	$ 841,594	$ 799,195	$ 967,366

Fair Value Measurements of Financial Assets and Liabilities

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

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012. 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, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Cash Flow Hedges:					
Commodity Hedges (a)	-	85	-	(6)	79
Total Risk Management Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Cash Flow Hedges:					
Commodity Hedges (a)	-	65	-	(6)	59
Total Risk Management Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

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

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

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2013, 2012 and 2011.

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, 2013	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(732)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	101
Transfers into Level 3 (d) (e)	273
Transfers out of Level 3 (e) (f)	(187)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	517
Balance as of December 31, 2013	$ 2,171

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.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of December 31, 2013 and 2012:

Significant Unobservable Inputs
December 31, 2013

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range High
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

Significant Unobservable Inputs
December 31, 2012

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input (a)	Forward Price Range Low	Forward Price Range 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.

11. INCOME TAXES

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

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ (4,828)	$ 13,617	$ (1,625)
Deferred	12,440	10,168	33,153
Deferred Investment Tax Credits	(230)	(278)	(359)
Income Tax Expense	$ 7,382	$ 23,507	$ 31,169

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

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Net Income	$ 8,906	$ 52,975	$ 53,976
Income Tax Expense	7,382	23,507	31,169
Pretax Income	$ 16,288	$ 76,482	$ 85,145
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 5,701	$ 26,769	$ 29,801
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	2,648	2,382	2,563
AFUDC	(749)	(894)	(818)
Removal Costs	(2,475)	(3,885)	(2,010)
Investment Tax Credits, Net	(230)	(278)	(359)
State and Local Income Taxes, Net	1,581	1,535	2,261
Tax Adjustments	1,097	(1,076)	751
Other	(191)	(1,046)	(1,020)
Income Tax Expense	$ 7,382	$ 23,507	$ 31,169
Effective Income Tax Rate	45.3 %	30.7 %	36.6 %

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

	December 31,	
	2013	2012
	(in thousands)	
Deferred Tax Assets	$ 56,347	$ 42,212
Deferred Tax Liabilities	(612,505)	(547,735)
Net Deferred Tax Liabilities	$ (556,158)	$ (505,523)
Property Related Temporary Differences	$ (436,812)	$ (410,100)
Amounts Due from Customers for Future Federal Income Taxes	(29,842)	(29,800)
Deferred State Income Taxes	(80,357)	(54,658)
Deferred Income Taxes on Other Comprehensive Loss	2,918	10,760
Regulatory Assets	(17,063)	(20,604)
All Other, Net	4,998	(1,121)
Net Deferred Tax Liabilities	$ (556,158)	$ (505,523)

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2011. 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 and was completed in the second quarter of 2013. 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 and KPCo and other AEP subsidiaries are currently under examination in several state and local jurisdictions. However, it is possible that previously filed tax returns have positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2009.

Tax Credit Carryforward

A federal income tax operating loss sustained in 2009 along with lower federal taxable income in 2012, 2011 and 2010 resulted in unused federal income tax credits of $232 thousand, not all of which have an expiration date. As of December 31, 2013, KPCo had federal general business tax credit carryforwards of $218 thousand. If these credits are not utilized, the federal general business tax credits will expire in the years 2029 through 2032.

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

Uncertain Tax Positions

KPCo recognizes interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation expense 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, 2013	2012	2011
		(in thousands)	
Interest Expense	$ -	$ 23	$ 193
Interest Income	99	-	1,849
Reversal of Prior Period Interest Expense	-	-	284

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

	December 31, 2013	2012
	(in thousands)	
Accrual for Receipt of Interest	$ 1	$ 1
Accrual for Payment of Interest and Penalties	98	92

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

	2013	2012	2011
		(in thousands)	
Balance as of January 1,	$ 1,333	$ 1,608	$ 2,711
Increase - Tax Positions Taken During a Prior Period	-	-	1,604
Decrease - Tax Positions Taken During a Prior Period	(725)	(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,	$ 608	$ 1,333	$ 1,608

The total amount of unrecognized tax benefits (costs) that, if recognized, would affect the effective tax rate is $0 thousand for 2013 and 2012 and $(4) thousand for 2011. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The 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 did have a favorable impact on cash flows in 2013.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to net income, cash flows or financial condition.

State Tax Legislation

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

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.0% to 6.5% in 2014. The enacted provisions will not materially impact KPCo's net income, cash flows or financial condition.

12. LEASES

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

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

	Years Ended December 31,		
Lease Rental Costs	**2013**	**2012**	**2011**
		(in thousands)	
Net Lease Expense on Operating Leases	$ 1,387	$ 1,141	$ 835
Amortization of Capital Leases	1,743	1,710	1,897
Interest on Capital Leases	311	311	344
Total Lease Rental Costs	$ 3,441	$ 3,162	$ 3,076

The following table shows the property, plant and equipment under capital leases and related obligations recorded on KPCo's balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on KPCo's balance sheets.

	December 31,	
	2013	**2012**
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 2,854	$ 2,776
Other Property, Plant and Equipment	3,425	4,618
Total Property, Plant and Equipment Under Capital Leases	6,279	7,394
Accumulated Amortization	1,869	2,576
Net Property, Plant and Equipment Under Capital Leases	$ 4,410	$ 4,818
Obligations Under Capital Leases		
Noncurrent Liability	$ 3,420	$ 3,128
Liability Due Within One Year	990	1,729
Total Obligations Under Capital Leases	$ 4,410	$ 4,857

Future minimum lease payments consisted of the following as of December 31, 2013:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2014	$ 1,147	$ 1,324
2015	1,025	1,153
2016	812	1,091
2017	672	923
2018	471	629
Later Years	851	1,493
Total Future Minimum Lease Payments	4,978	$ 6,613
Less Estimated Interest Element	568	
Estimated Present Value of Future Minimum Lease Payments	$ 4,410	

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, 2013, the maximum potential loss for these lease agreements was approximately $1.1 million assuming the fair value of the equipment is zero at the end of the lease term.

13. 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, 2013 and 2012:

Type of Debt	Maturity	Weighted Average Interest rate as of December 31, 2013	Interest Rate Ranges as of December 31, 2013	Interest Rate Ranges as of December 31, 2012	Outstanding as of December 31, 2013	Outstanding as of December 31, 2012
					(in thousands)	
Senior Unsecured Notes	2017-2039	6.40%	5.625%-8.13%	5.625%-8.13%	$ 530,000	$ 780,000
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Other Long-term Debt (a)	2015	1.188%	1.188%		200,000	-
Unamortized Discount, Net					(611)	(805)
Total Long-term Debt Outstanding					749,389	799,195
Long-term Debt Due Within One Year					-	250,000
Long-term Debt					$ 749,389	$ 549,195

(a) In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. In 2013, OPCo borrowed $1 billion under the credit facility and retired other certain debt. On December 31, 2013, OPCo assigned the $1 billion in credit facility borrowings to AGR upon the transfer of OPCo's generation assets to AGR. Also on December 31, 2013, AGR subsequently assigned a portion of the borrowings to KPCo in the amount of $200 million upon AGR's transfer of certain of those generation assets.

Long-term debt outstanding as of December 31, 2013 is payable as follows:

	2014	2015	2016	2017	2018	After 2018	Total
				(in thousands)			
Principal Amount	$ -	$ 220,000	$ -	$ 325,000	$ -	$ 205,000	$ 750,000
Unamortized Discount, Net							(611)
Total Long-term Debt Outstanding							$ 749,389

Dividend Restrictions

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

Federal Power Act

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

Leverage Restrictions

Pursuant to the credit agreement leverage restrictions, KPCo must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. As of December 31, 2013, none of KPCo's retained earnings have restrictions related to the payment of dividends to Parent.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2013 and 2012 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2013 and 2012 are described in the following table:

Year	Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2013	$ 32,649	$ 31,421	$ 10,911	$ 14,584	$ 8,564	$ 250,000
2012	13,359	80,205	9,200	46,187	13,359	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, 2013, 2012 and 2011 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2013	0.43 %	0.29 %	0.41 %	0.24 %	0.37 %	0.32 %
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 Expense and Interest Income, respectively, on KPCo's statements of income. For amounts borrowed from and advanced to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	2012	2011
		(in thousands)	
Interest Expense	$ 12	$ 1	$ -
Interest Income	36	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. The costs of customer accounts receivable sold are reported in Other Operation expense on KPCo's statements of income. KPCo manages and services its accounts receivable sold.

In June 2013, AEP Credit amended its receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. AEP Credit amended a commitment of $385 million to now expire in June 2014. The remaining commitment of $315 million expires in June 2015. AEP Credit intends to extend or replace the agreement expiring in June 2014 on or before its maturity.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $43 million and $46 million as of December 31, 2013 and 2012, 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, 2013, 2012 and 2011.

KPCo's proceeds on the sale of receivables to AEP Credit were $522 million, $517 million and $579 million for the years ended December 31, 2013, 2012 and 2011, respectively.

14. RELATED PARTY TRANSACTIONS

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

Interconnection Agreement

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

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

Effective January 1, 2014, the FERC approved the creation of the Power Coordination Agreement among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Also effective January 1, 2014, the FERC approved the Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM. See "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters in Note 3.

Prior to January 1, 2014, power, natural gas and risk management activities were conducted by AEPSC and profits and losses were allocated under the SIA to members of the Interconnection Agreement, PSO and SWEPCo. Risk management activities involved the purchase and sale of power and natural gas under physical forward contracts at fixed and variable prices. In addition, the risk management of power, and to a lesser extent natural gas contracts, included exchange traded futures and options and OTC options and swaps. The majority of these transactions represented physical forward contracts in the AEP System's traditional marketing area and were typically settled by entering into offsetting contracts. In addition, AEPSC entered into transactions for the purchase and sale of power and natural gas options, futures and swaps, and for the forward purchase and sale of power outside of the AEP System's traditional marketing area.

Operating Agreement

PSO, SWEPCo and AEPSC are parties to the Operating Agreement which was approved by the FERC. The Operating Agreement requires PSO and SWEPCo to maintain adequate annual planning reserve margins and requires that capacity in excess of the required margins be made available for sale to other operating companies as capacity commitments. 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 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 (prior to January 1, 2014) and the 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 the 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 the 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.

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, 2013, 2012 and 2011:

	Years Ended December 31,		
Related Party Revenues	**2013**	**2012**	**2011**
		(in thousands)	
Sales under Interconnection Agreement	$ 79,909	$ 60,198	$ 99,593
Direct Sales to West Affiliates	119	64	314
Transmission Agreement Sales	862	3,022	4,480
Natural Gas Contracts with AEPES	-	-	32
Other Revenues	22,841	7,492	263
Total Affiliated Revenues	$ 103,731	$ 70,776	$ 104,682

The following table shows the purchased power expenses incurred for purchases under the Interconnection Agreement and from affiliates for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
Related Party Purchases	**2013**	**2012**	**2011**
		(in thousands)	
Purchases under Interconnection Agreement	$ 161,293	$ 121,267	$ 112,217
Direct Purchases from West Affiliates	1	11	51
Purchases from AEGCo	107,794	102,371	98,031
Total Affiliated Purchases	$ 269,088	$ 223,649	$ 210,299

The above summarized related party revenues and expenses are reported in Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on KPCo's statements of income.

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

KPCo's net charges recorded as a result of the TA for the years ended December 31, 2013, 2012 and 2011 were $3 million, $1.1 million and $410 thousand, respectively, and were recorded in Other Operation expenses on KPCo's statements of income.

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 natural 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 natural 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 natural gas managed by AEPES were $124 thousand, $173 thousand and $183 thousand for the years ended December 31, 2013, 2012 and 2011, respectively. These purchases are reflected in Purchased Electricity for Resale on KPCo's statements of income.

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 $4 million, $1.6 million and $2.2 million in 2013, 2012 and 2011, respectively, for urea transloading provided by I&M. These expenses were recorded as fuel expenses or other operation expenses.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers the cost of performing these services on the balance sheet, then transfers the cost to the affiliate for reimbursement. KPCo recorded its assigned portion of these billings as capital or maintenance expenses depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $1.1 million, $647 thousand and $672 thousand for the years ended December 31, 2013, 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 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:

	December 31,	
Billing Company	**2013**	**2012**
	(in thousands)	
AGR	$ (20)	$ 381
APCo	26	436

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 Purchased Electricity for Resale on KPCo's 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, recorded at net book value, for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in thousands)	
Sales	$ 951	$ 1,032	$ 404
Purchases	1,702	1,078	2,188

The amounts above are recorded in Property, Plant and Equipment on the balance sheets.

Global Borrowing Notes

As of December 31, 2013 and 2012, AEP has an intercompany note in place with KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's balance sheets. KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accrued Interest on KPCo's balance sheets.

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.

15. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the years ended December 31, 2013, 2012 and 2011 were $38 million, $40 million and $35 million, respectively. The carrying amount of liabilities associated with AEPSC as of December 31, 2013 and 2012 was $4 million and $6 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the years ended December 31, 2013, 2012 and 2011 were $108 million, $102 million and $98 million, respectively. The carrying amount of liabilities associated with AEGCo as of December 31, 2013 and 2012 was $11 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Property, Plant and Equipment on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide KPCo's annual property information:

2013	Regulated (a)				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 1,052,757	$ 365,645	3.7%	40-60	$ -	$ -	NA	NA
Transmission	507,844	172,604	1.8%	25-75	-	-	NA	NA
Distribution	693,481	216,771	3.4%	11-75	-	-	NA	NA
CWIP	128,599	(8,320)	NM	NM	-	-	NA	NA
Other	475,229	196,977	4.3%	20-75	5,530	212	NM	NM
Total	$ 2,857,910	$ 943,677			$ 5,530	$ 212		

2012	Regulated				Nonregulated (a)			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate	Depreciable Life Ranges
	(in thousands)			(in years)	(in thousands)			(in years)
Generation	$ 558,935	$ 221,976	3.8%	40-50	$ 880,064	$ 277,074	3.8%	60
Transmission	490,152	162,774	1.6%	25-75	5,829	3,082	2.3%	NM
Distribution	652,615	200,340	3.4%	11-75	-	-	NA	NA
CWIP	44,281	(6,327)	NM	NM	43,643	380	NM	NM
Other	57,451	24,409	7.2%	20-75	7,699	308	NM	NM
Total	$ 1,803,434	$ 603,172			$ 937,235	$ 280,844		

2011	Regulated		Nonregulated (a)	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	3.8%	40-50	3.8%	60
Transmission	1.7%	25-75	2.4%	NA
Distribution	3.5%	11-75	NA	NA
CWIP	NM	NM	NM	NM
Other	8.2%	NM	3.4%	NM

(a) For 2013, KPCo's ownership in the Mitchell Plant is included in the Regulated amounts listed above. For 2012 and 2011, KPCo's ownership in the Mitchell Plant is included in the Nonregulated amounts listed above.

NA Not applicable.

NM Not meaningful.

The composite depreciation rate generally includes a component for nonasset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability.

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.

The following is a reconciliation of the 2013 and 2012 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)			
2013	$ 8,759	$ 742	$ -	$ (255)	$ 11,280	$ 20,526
2012	8,488	709	-	(438)	-	8,759

Allowance for Funds Used During Construction (AFUDC)

KPCo's amounts of allowance for borrowed and equity funds used during construction are summarized in the following table:

	Years Ended December 31, 2013	2012	2011
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 1,367	$ 1,574	$ 1,229
Allowance for Borrowed Funds Used During Construction	3,047	2,275	996

Jointly-owned Electric Facilities

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

	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in thousands)	
KPCo's Share as of December 31, 2013					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 907,304	$ 75,253	$ 305,170
KPCo's Share as of December 31, 2012					
Mitchell Generating Station, Units 1 and 2 (a)	Coal	50.0 %	$ 878,036	$ 43,106	$ 276,658

(a) Operated by KPCo.

17. 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 facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was 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 of $2 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of December 31, 2013
(in thousands)					
$ 497	$ 180	$ -	$ (276)	$ (401)	$ -

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the statements of income. Management does not expect additional costs to be incurred related to this initiative.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In management's opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. KPCo's unaudited quarterly financial information is as follows:

	2013 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 230,644	$ 181,549	$ 211,536	$ 202,526
Operating Income (Loss)	32,607	18,214	(14,044)(a)	22,422
Net Income (Loss)	14,403	4,985	(16,513)(a)	6,031

	2012 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in thousands)			
Total Revenues	$ 210,365	$ 185,183	$ 213,995	$ 214,874
Operating Income	29,309	33,392	34,990	26,241
Net Income	12,154	15,345	15,754	9,722

(a) Includes a regulatory disallowance for Big Sandy Plant, Unit 2 (see Note 3 and Note 6).

Kentucky Power Company

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Financial Statements

AEP AMERICAN ELECTRIC POWER

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GLOSSARY OF TERMS

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
REVENUES		
Electric Generation, Transmission and Distribution	$ 227,631	$ 201,315
Sales to AEP Affiliates	5,415	29,197
Other Revenues	84	132
TOTAL REVENUES	233,130	230,644
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	72,362	74,680
Purchased Electricity for Resale	3,113	3,370
Purchased Electricity from AEP Affiliates	31,422	56,490
Other Operation	19,865	18,333
Maintenance	18,642	17,083
Depreciation and Amortization	23,522	23,109
Taxes Other Than Income Taxes	5,303	4,972
TOTAL EXPENSES	174,229	198,037
OPERATING INCOME	58,901	32,607
Other Income (Expense):		
Interest Income	33	27
Allowance for Equity Funds Used During Construction	1,456	261
Interest Expense	(9,101)	(11,572)
INCOME BEFORE INCOME TAX EXPENSE	51,289	21,323
Income Tax Expense	18,741	6,920
NET INCOME	$ 32,548	$ 14,403

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
Net Income	$ 32,548	$ 14,403
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $5 and $118 in 2014 and 2013, Respectively	10	218
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $63 and $134 in 2014 and 2013, Respectively	117	248
TOTAL OTHER COMPREHENSIVE INCOME	127	466
TOTAL COMPREHENSIVE INCOME	$ 32,675	$ 14,869

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 50,450	$ 531,536	$ 190,819	$ (19,994)	$ 752,811
Capital Contribution from Parent		231			231
Common Stock Dividends			(3,892)		(3,892)
Net Income			14,403		14,403
Other Comprehensive Income				466	466
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	$ 50,450	$ 531,767	$ 201,330	$ (19,528)	$ 764,019
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(15,000)		(15,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			32,548		32,548
Other Comprehensive Income				127	127
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2014	$ 50,450	$ 517,460	$ 197,239	$ (6,601)	$ 758,548

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,244	$ 743
Accounts Receivable:		
Customers	11,974	17,889
Affiliated Companies	28,281	9,781
Accrued Unbilled Revenues	12	857
Miscellaneous	106	75
Allowance for Uncollectible Accounts	(63)	(78)
Total Accounts Receivable	40,310	28,524
Fuel	45,433	92,313
Materials and Supplies	41,141	43,940
Risk Management Assets	4,277	4,356
Accrued Tax Benefits	35	5,249
Regulatory Asset for Under-Recovered Fuel Costs	10,594	-
Prepayments and Other Current Assets	5,595	3,284
TOTAL CURRENT ASSETS	148,629	178,409
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,063,586	1,052,757
Transmission	510,963	507,844
Distribution	698,685	693,481
Other Property, Plant and Equipment (Including Plant to be Retired)	477,716	480,759
Construction Work in Progress	139,321	128,599
Total Property, Plant and Equipment	2,890,271	2,863,440
Accumulated Depreciation and Amortization	962,785	943,889
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,927,486	1,919,551
OTHER NONCURRENT ASSETS		
Regulatory Assets	214,765	216,360
Long-term Risk Management Assets	2,880	3,484
Employee Benefits and Pension Assets	13,804	11,446
Deferred Charges and Other Noncurrent Assets	14,618	20,207
TOTAL OTHER NONCURRENT ASSETS	246,067	251,497
TOTAL ASSETS	$ 2,322,182	$ 2,349,457

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2014 and December 31, 2013
(Unaudited)

	March 31, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 49,404	$ 8,564
Accounts Payable:		
General	42,993	21,619
Affiliated Companies	25,648	39,171
Risk Management Liabilities	905	1,828
Customer Deposits	25,289	25,211
Deferred Income Taxes	10,055	6,486
Accrued Taxes	26,216	20,801
Accrued Interest	5,640	6,678
Regulatory Liability for Over-Recovered Fuel Costs	-	2,851
Other Current Liabilities	20,681	19,411
TOTAL CURRENT LIABILITIES	206,831	152,620
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	729,430	729,389
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	1,630	2,105
Deferred Income Taxes	546,344	549,672
Regulatory Liabilities and Deferred Investment Tax Credits	24,490	22,926
Employee Benefits and Pension Obligations	7,754	6,041
Deferred Credits and Other Noncurrent Liabilities	27,155	27,335
TOTAL NONCURRENT LIABILITIES	1,356,803	1,357,468
TOTAL LIABILITIES	1,563,634	1,510,088
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER’S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	517,460	614,648
Retained Earnings	197,239	179,691
Accumulated Other Comprehensive Income (Loss)	(6,601)	(5,420)
TOTAL COMMON SHAREHOLDER’S EQUITY	758,548	839,369
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,322,182	$ 2,349,457

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
OPERATING ACTIVITIES		
Net Income	$ 32,548	$ 14,403
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	23,522	23,109
Deferred Income Taxes	2,118	7,924
Allowance for Equity Funds Used During Construction	(1,456)	(261)
Mark-to-Market of Risk Management Contracts	(707)	1,798
Property Taxes	3,784	3,603
Fuel Over/Under-Recovery, Net	(13,445)	(7,945)
Change in Other Noncurrent Assets	626	373
Change in Other Noncurrent Liabilities	717	1,017
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(11,786)	15,743
Fuel, Materials and Supplies	49,679	25,257
Accounts Payable	(505)	(35,052)
Accrued Taxes, Net	10,629	(76)
Accrued Interest	(1,038)	(5,229)
Other Current Assets	(1,530)	904
Other Current Liabilities	1,481	(6,083)
Net Cash Flows from Operating Activities	94,637	39,485
INVESTING ACTIVITIES		
Construction Expenditures	(20,979)	(35,241)
Acquisitions of Assets	(1,036)	(18)
Proceeds from Sales of Assets	85	1,255
Other Investing Activities	98	-
Net Cash Flows Used for Investing Activities	(21,832)	(34,004)
FINANCING ACTIVITIES		
Capital Contribution from (Returned to) Parent	(100,000)	231
Change in Advances from Affiliates, Net	40,840	(2,320)
Principal Payments for Capital Lease Obligations	(1,208)	(317)
Dividends Paid on Common Stock	(15,000)	(3,892)
Other Financing Activities	3,064	197
Net Cash Flows Used for Financing Activities	(72,304)	(6,101)
Net Increase (Decrease) in Cash and Cash Equivalents	501	(620)
Cash and Cash Equivalents at Beginning of Period	743	1,482
Cash and Cash Equivalents at End of Period	$ 1,244	$ 862
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 9,888	$ 16,596
Net Cash Paid for Income Taxes	-	111
Noncash Acquisitions Under Capital Leases	596	721
Construction Expenditures Included in Current Liabilities as of March 31,	15,540	19,185

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

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed financial statements are unaudited and should be read in conjunction with the audited 2013 financial statements and notes thereto, which are included in KPCo's 2013 Annual Report.

Management reviewed subsequent events through April 25, 2014, the date that the first quarter 2014 report was issued.

Revenue Recognition

Electricity Supply and Delivery Activities – Transactions with PJM

Revenues are recognized 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 include unbilled as well as billed amounts.

KPCo sells power produced at its generation plants to PJM and purchase power from PJM to supply its retail load. These power sales and purchases for retail load are netted hourly for financial reporting purposes. On an hourly net basis, KPCo records sales of power to PJM in excess of purchases of power as revenues. Also, on an hourly net basis, KPCo records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale. Upon termination of the Interconnection Agreement, KPCo manages and accounts for its purchases and sales with PJM individually based on market prices.

2. NEW ACCOUNTING PRONOUNCEMENT

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

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

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

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management plans to adopt ASU 2014-08 effective January 1, 2015.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three months ended March 31, 2014 and 2013. All amounts in the following tables are presented net of related income taxes.

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

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

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (19,585)	$ (19,994)
Change in Fair Value Recognized in AOCI	161	-	-	161
Amounts Reclassified from AOCI	42	15	248	305
Net Current Period Other Comprehensive Income	203	15	248	466
Balance in AOCI as of March 31, 2013	$ 76	$ (267)	$ (19,337)	$ (19,528)

Reclassifications Out of Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the three months ended March 31, 2014 and 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended March 31,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$ -	$ 19
Purchased Electricity for Resale	(452)	54
Other Operation Expense	(3)	(3)
Maintenance Expense	(5)	(2)
Property, Plant and Equipment	(6)	(4)
Regulatory Assets/(Liabilities), Net (a)	(43)	-
Subtotal - Commodity	(509)	64
Interest Rate and Foreign Currency:		
Interest Expense	23	23
Subtotal - Interest Rate and Foreign Currency	23	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	(486)	87
Income Tax (Expense) Credit	(170)	30
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(316)	57
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(54)	(91)
Amortization of Actuarial (Gains)/Losses	234	472
Reclassifications from AOCI, before Income Tax (Expense) Credit	180	381
Income Tax (Expense) Credit	63	133
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	117	248
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (199)	$ 305

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

4. RATE MATTERS

As discussed in KPCo's 2013 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2013 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2014 and updates KPCo's 2013 Annual Report.

Regulatory Assets Not Yet Being Recovered

	March 31, 2014	December 31, 2013
Noncurrent Regulatory Assets	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 12,146	$ 12,146
Total Regulatory Assets Not Yet Being Recovered	$ 12,146	$ 12,146

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

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. 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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of March 31, 2014, the net book value of Big Sandy Plant, Unit 2 was $247 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed. If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

5. <u>COMMITMENTS, GUARANTEES AND CONTINGENCIES</u>

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2013 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2014, 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 conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2014, the maximum potential loss for these lease agreements was approximately $1.2 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans for the three months ended March 31, 2014 and 2013:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$ 575	$ 470	$ 118	$ 208
Interest Cost	2,010	1,827	601	643
Expected Return on Plan Assets	(2,418)	(2,564)	(1,060)	(1,030)
Amortization of Prior Service Cost (Credit)	14	14	(606)	(611)
Amortization of Net Actuarial Loss	1,117	1,651	187	588
Net Periodic Benefit Cost (Credit)	$ 1,298	$ 1,398	$ (760)	$ (202)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, 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 extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt 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 the KPCo's outstanding derivative contracts as of March 31, 2014 and December 31, 2013:

Notional Volume of Derivative Instruments

	Volume		
	March 31, 2014	**December 31, 2013**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	5,900	10,071	MWhs
Coal	447	2	Tons
Natural Gas	398	509	MMBtus
Heating Oil and Gasoline	190	261	Gallons
Interest Rate	$ 2,236	$ 2,615	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 and natural gas ("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. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. For disclosure purposes, these contracts were included with other hedging activities as "Commodity" as of December 31, 2013. As of March 31, 2014, these contracts will be grouped as "Commodity" with other risk management activities. KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. 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 condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2014 and December 31, 2013 condensed balance sheets, KPCo netted $7 thousand and $0 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $280 thousand and $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 KPCo's derivative activity on the condensed balance sheets as of March 31, 2014 and December 31, 2013:

Fair Value of Derivative Instruments
March 31, 2014

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 8,291	$ 46	$ -	$ 8,337	$ (4,060)	$ 4,277
Long-term Risk Management Assets	3,557	-	-	3,557	(677)	2,880
Total Assets	11,848	46	-	11,894	(4,737)	7,157
Current Risk Management Liabilities	5,151	18	-	5,169	(4,264)	905
Long-term Risk Management Liabilities	2,376	-	-	2,376	(746)	1,630
Total Liabilities	7,527	18	-	7,545	(5,010)	2,535
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,321	$ 28	$ -	$ 4,349	$ 273	$ 4,622

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 9,520	$ 85	$ -	$ 9,605	$ (5,249)	$ 4,356
Long-term Risk Management Assets	4,306	-	-	4,306	(822)	3,484
Total Assets	13,826	85	-	13,911	(6,071)	7,840
Current Risk Management Liabilities	7,583	65	-	7,648	(5,820)	1,828
Long-term Risk Management Liabilities	2,970	-	-	2,970	(865)	2,105
Total Liabilities	10,553	65	-	10,618	(6,685)	3,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,273	$ 20	$ -	$ 3,293	$ 614	$ 3,907

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

The table below presents KPCo's activity of derivative risk management contracts for the three months ended March 31, 2014 and 2013:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2014 and 2013

Location of Gain (Loss)	2014	2013
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 6,940	$ 596
Fuel and Other Consumables Used for Electric Generation	1	-
Regulatory Assets (a)	-	-
Regulatory Liabilities (a)	1,120	(467)
Total Gain on Risk Management Contracts	$ 8,061	$ 129

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. 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 Expense on KPCo's condensed statements of income. During the three months ended March 31, 2014 and 2013, 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 (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2014 and 2013, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three months ended March 31, 2013, KPCo designated heating oil and gasoline derivatives as cash flow hedges. KPCo discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2014 and 2013, 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 (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2014 and 2013, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2014 and 2013, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2014 and 2013, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of March 31, 2014 and December 31, 2013 were:

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

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 43	$ -	$ 43
Hedging Liabilities (a)	15	-	15
AOCI Gain (Loss) Net of Tax	17	(206)	(189)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	17	(60)	(43)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 79	$ -	$ 79
Hedging Liabilities (a)	59	-	59
AOCI Gain (Loss) Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2014, 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 was 2 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (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 March 31, 2014 and December 31, 2013:

	March 31, 2014	December 31, 2013
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 57	$ 118
Amount of Collateral KPCo Would Have Been Required to Post	1,079	565
Amount Attributable to RTO and ISO Activities	981	522

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of March 31, 2014 and December 31, 2013:

	March 31, 2014	December 31, 2013
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 3,366	$ 4,039
Amount of Cash Collateral Posted	-	-
Additional Settlement Liability if Cross Default Provision is Triggered	2,644	3,817

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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

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

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo's Long-term Debt as of March 31, 2014 and December 31, 2013 are summarized in the following table:

	March 31, 2014		December 31, 2013	
	Book Value	**Fair Value**	**Book Value**	**Fair Value**
		(in thousands)		
Long-term Debt	$ 749,430	$ 860,557	$ 749,389	$ 841,594

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2014 and December 31, 2013. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 81	$ 9,058	$ 2,087	$ (4,112)	$ 7,114
Cash Flow Hedges:					
Commodity Hedges (a)	-	46	-	(3)	43
Total Risk Management Assets	$ 81	$ 9,104	$ 2,087	$ (4,115)	$ 7,157
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 63	$ 6,205	$ 637	$ (4,385)	$ 2,520
Cash Flow Hedges:					
Commodity Hedges (a)	-	18	-	(3)	15
Total Risk Management Liabilities	$ 63	$ 6,223	$ 637	$ (4,388)	$ 2,535

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Cash Flow Hedges:					
Commodity Hedges (a)	-	85	-	(6)	79
Total Risk Management Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Cash Flow Hedges:					
Commodity Hedges (a)	-	65	-	(6)	59
Total Risk Management Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

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

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2014 and 2013.

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

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

Three Months Ended March 31, 2013	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(297)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	55
Transfers into Level 3 (d) (e)	126
Transfers out of Level 3 (e) (f)	(107)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(172)
Balance as of March 31, 2013	$ 1,804

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of March 31, 2014 and December 31, 2013:

Significant Unobservable Inputs
March 31, 2014

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	**Liabilities**	**Technique**	**Unobservable Input (a)**	**Low**	**High**
	(in thousands)					
Energy Contracts	$ 1,327	$ 580	Discounted Cash Flow	Forward Market Price	$ 13.34	$ 59.60
FTRs	760	57	Discounted Cash Flow	Forward Market Price	(5.05)	9.17
Total	$ 2,087	$ 637				

Significant Unobservable Inputs
December 31, 2013

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	**Liabilities**	**Technique**	**Unobservable Input (a)**	**Low**	**High**
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

(a) Represents market prices in dollars per MWh.

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. The IRS examination of years 2011 and 2012 started in April 2014. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

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

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2014.

Dividend Restrictions

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

Federal Power Act

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

Leverage Restrictions

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

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of March 31, 2014 and December 31, 2013 are included in Advances from Affiliates on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2014 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of March 31, 2014	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 50,366	$ 50,332	$ 20,343	$ 34,026	$ 49,404	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the three months ended March 31, 2014 and 2013 are summarized in the following table:

Three Months Ended March 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2014	0.33 %	0.28 %	0.33 %	0.28 %	0.31 %	0.32 %
2013	0.43 %	0.35 %	0.36 %	0.36 %	0.38 %	0.36 %

Sale of Receivables – AEP Credit

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

AEP Credit's receivables securitization agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2014. The remaining commitment of $315 million expires in June 2015. AEP Credit intends to extend or replace the agreement expiring in June 2014 on or before its maturity.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $60 million and $43 million as of March 31, 2014 and December 31, 2013, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended March 31, 2014 and 2013 were $763 thousand and $520 thousand, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended March 31, 2014 and 2013 were $179 million and $140 million, respectively.

12. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended March 31, 2014 and 2013 were $13 million and $7 million, respectively. The carrying amount of liabilities associated with AEPSC as of March 31, 2014 and December 31, 2013 was $5 million and $4 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended March 31, 2014 and 2013 were $30 million and $25 million, respectively. The carrying amount of liabilities associated with AEGCo as of March 31, 2014 and December 31, 2013 was $11 million and $11 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

APPENDIX B

DESCRIPTION OF SUMITOMO MITSUI BANKING CORPORATION

The information included in this Appendix B has been obtained from the Bank. None of the Issuer, the Company or the Underwriter makes any representation as to the accuracy or completeness of such information.

The delivery of the Official Statement shall not create any implication that there has been no change in the affairs of Sumitomo Mitsui Banking Corporation since the date hereof, or that the information contained or referred to in this Appendix B is correct as of any time subsequent to its date.

SUMITOMO MITSUI BANKING CORPORATION

Sumitomo Mitsui Banking Corporation (*Kabushiki Kaisha Mitsui Sumitomo Ginko*) ("SMBC") is a joint stock corporation with limited liability (*Kabushiki Kaisha*) under the laws of Japan. The registered head office of SMBC is located at 1-2, Marunouchi 1-chome, Chiyoda-ku, Tokyo 100-0005, Japan.

SMBC was established in April 2001 through the merger of two leading banks, The Sakura Bank, Limited and The Sumitomo Bank, Limited. In December 2002, Sumitomo Mitsui Financial Group, Inc. ("SMFG") was established through a stock transfer as a holding company under which SMBC became a wholly owned subsidiary. **SMFG reported ¥ 161,534,387 million (USD 1,564,702 million) in consolidated total assets as of March 31, 2014.**

SMBC is one of the world's leading commercial banks and provides an extensive range of banking services to its customers in Japan and overseas. In Japan, SMBC accepts deposits, makes loans and extends guarantees to corporations, individuals, governments and governmental entities. It also offers financing solutions such as syndicated lending, structured finance and project finance. SMBC also underwrites and deals in bonds issued by or under the guarantee of the Japanese government and local government authorities, and acts in various administrative and advisory capacities for certain types of corporate and government bonds. Internationally, SMBC operates through a network of branches, representative offices, subsidiaries and affiliates to provide many financing products including syndicated lending and project finance.

The New York Branch of SMBC is licensed by the State of New York Banking Department to conduct branch banking business at 277 Park Avenue, New York, New York, and is subject to examination by the State of New York Banking Department and the Federal Reserve Bank of New York.

Financial and Other Information

Audited consolidated financial statements for SMFG and its consolidated subsidiaries for the fiscal years ended March 31, 2013, as well as other corporate data, financial information and analyses are available in English on the website of the Parent at www.smfg.co.jp/english.

The information herein has been obtained from SMBC, which is solely responsible for its content. The delivery of the Official Statement shall not create any implication that there has been no change in the affairs of SMBC since the date hereof, or that the information contained or referred herein is correct as of any time subsequent to its date.

APPENDIX C

PROPOSED FORM OF OPINION OF BOND COUNSEL

We have examined the transcript of proceedings relating to the issuance by the West Virginia Economic Development Authority (the "Issuer") of $65,000,000 principal amount of Solid Waste Disposal Facilities Revenue Refunding Bonds (Kentucky Power Company – Mitchell Project), Series 2014A (the "Bonds"). The Bonds are being issued pursuant to Chapter 31, Article 15, Section 1, et seq., of the Code of West Virginia, 1931 (the "Act"), for the purpose of making a loan to assist Kentucky Power Company (the "Company") in the refunding of $65,000,000 Solid Waste Disposal Facilities Revenue Refunding Bonds (Ohio Power Company – Mitchell Project), Series 2008A, previously issued by the Issuer to assist a certain affiliate of the Company in refinancing of a portion of the costs of acquiring, constructing and installing certain solid waste disposal facilities qualified for financing under the Act, as more particularly described in the Indenture of Trust dated as of June 15, 2014 (the "Indenture") between the Issuer and The Bank of New York Mellon Trust Company, N.A., as trustee (the "Trustee"), and in the Loan Agreement dated as of June 15, 2014 (the "Agreement") between the Issuer and the Company. We have also examined executed counterparts of the Indenture and the Agreement and a conformed copy of an executed Bond.

Based on such examination and subject to the limitations stated below, we are of the opinion that, under existing law:

1. The Bonds, the Indenture and the Agreement are valid and binding obligations of the Issuer, enforceable in accordance with their respective terms.

2. The Bonds constitute special obligations of the Issuer, and the principal of and interest on the Bonds and the purchase price of the Bonds (collectively, "debt charges") are payable solely from the revenues and other moneys assigned by the Indenture to secure those payments. Those revenues and other moneys include the payments required to be made by the Company under its promissory note delivered to the Issuer, and irrevocably assigned by the Issuer to the Trustee, all pursuant to the Agreement. The payment of debt service on the Bonds is not secured by an obligation or pledge of any money raised by taxation, and the Bonds do not represent or constitute a general obligation or a pledge of the faith and credit of the Issuer, the State of West Virginia or any of its political subdivisions.

3. Interest on the Bonds is excluded from gross income for federal income tax purposes under Section 103(a) of the Internal Revenue Code of 1986, as amended (the "Code"), except interest on any Bond for any period during which it is held by a "substantial user" or a "related person" as those terms are used in Section 147(a) of the Code, and is an item of tax preference for purposes of the federal alternative minimum tax imposed on individuals and corporations. The Bonds, and all interest and income thereon, are exempt from all taxation by the State of West Virginia and any county, municipality, political subdivision or agency thereof, except inheritance taxes. We express no opinion as to any other tax consequences regarding the Bonds.

The opinions stated above are based on an analysis of existing laws, regulations, rulings and court decisions and cover certain matters not directly addressed by such authorities. In rendering all such opinions, we assume, without independent verification, and rely upon (i) the accuracy of the factual matters represented, warranted or certified in the proceedings and documents we have examined, (ii) the due and legal authorization, execution and delivery of those documents by, and the valid, binding and enforceable nature of those documents upon, any parties other than the Issuer and (iii) the correctness of the legal conclusions contained in the legal opinion letter of counsel to the Company and in the legal opinion letter of counsel to the Issuer delivered in connection with this matter.

In rendering those opinions with respect to the treatment of the interest on the Bonds under the federal tax laws, we further assume and rely upon compliance with the covenants in the proceedings and documents we have examined, including those of the Issuer and the Company. Failure to comply with certain of those covenants subsequent to issuance of the Bonds may cause interest on the Bonds to be included in gross income for federal income tax purposes retroactively to their date of issuance.

The rights of the owners of the Bonds and the enforceability of the Bonds, the Indenture and the Agreement are subject to bankruptcy, insolvency, arrangement, fraudulent conveyance or transfer, reorganization, moratorium and other laws relating to or affecting creditors' rights, to the application of equitable principles, to the exercise of judicial discretion, and to limitations on legal remedies against public entities.

We express no opinion with respect to any indemnification, contribution, penalty, choice of law, choice of forum, choice of venue, waiver or severability provisions contained in the Bonds, the Indenture or the Agreement.

The opinions rendered in this letter are stated only as of this date, and no other opinion shall be implied or inferred as a result of anything contained in or omitted from this letter. Our engagement as bond counsel with respect to the Bonds has concluded on this date.

Respectfully submitted,

Filing Requirement
807 KAR 5:001 Section 16 (4)(q)

Filing Requirement:

Annual report to shareholders, or members, and statistical supplements covering the two (2) most recent years from the utility's application filing date;

Response:

Please see the attached copies of Kentucky Power's annual reports to the Board of Directors and Shareholder for the years ended December 2012 and 2013.

Appendix A to the
Proxy Statement

American Electric Power

2012 Annual Report

Audited Consolidated Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

AMERICAN ELECTRIC POWER
1 Riverside Plaza
Columbus, Ohio 43215-2373

CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEPGenCo	AEP Generation Resources Inc., a nonregulated AEP subsidiary in the Generation and Marketing segment.
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.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
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.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
BOA	Bank of America Corporation.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES	Competitive Retail Electric Service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
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, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.

Term	Meaning
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Charge.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETA	Electric Transmission America, LLC an equity interest joint venture with MidAmerican Energy Holdings Company America Transco, LLC formed to own and operate electric transmission facilities in North America outside of ERCOT.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IEU	Industrial Energy Users-Ohio.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
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.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NEIL	Nuclear Electric Insurance Limited insures domestic and international nuclear utilities for the costs associated with interruptions, damages, decontaminations and related nuclear risks.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.
NSR	New Source Review.
OATT	Open Access Transmission Tariff.

Term	Meaning
OCC	Corporation Commission of the State of Oklahoma.
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.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
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, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEET	Significantly Excessive Earnings Test.
SEC	U.S. Securities and Exchange Commission.
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.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 543 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW pulverized coal ultra-supercritical generating unit in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, coal, natural gas and other energy-related commodities.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for electricity, coal, natural gas and other energy-related commodities.

- Changes in utility regulation, including the implementation of ESPs and the transition to market and expected legal separation for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate the Interconnection Agreement.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of our debt.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see “Risk Factors” in Part I of this report.

AEP COMMON STOCK AND DIVIDEND INFORMATION

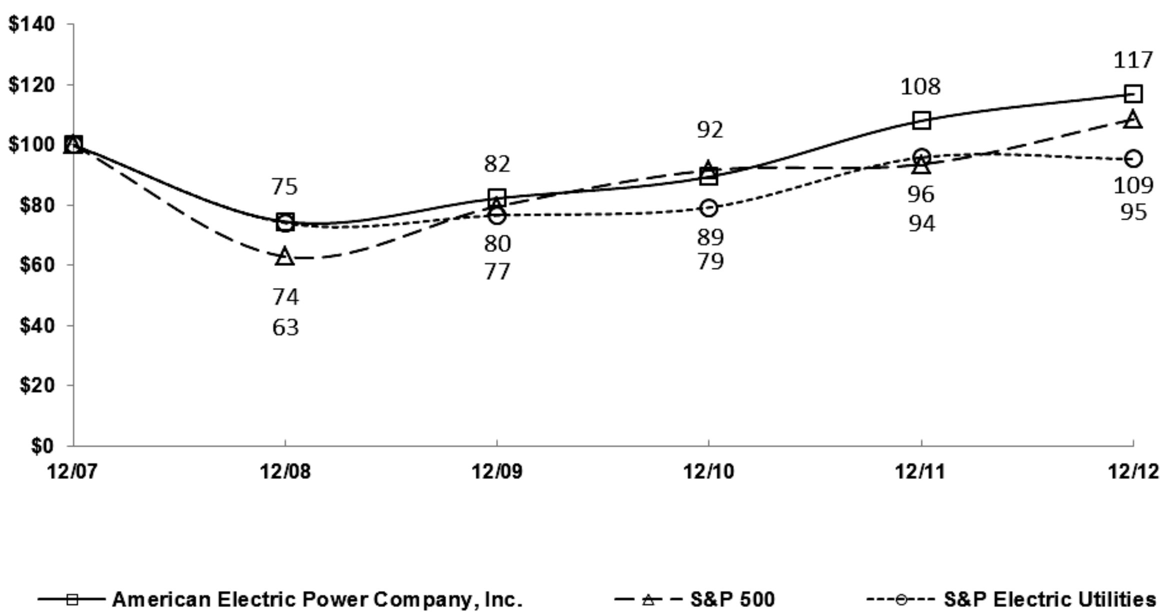
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High	Low	Quarter-End Closing Price	Dividend
December 31, 2012	$ 45.41	$ 40.56	$ 42.68	$ 0.47
September 30, 2012	44.84	39.62	43.94	0.47
June 30, 2012	40.46	36.97	39.90	0.47
March 31, 2012	41.98	37.46	38.58	0.47
December 31, 2011	$ 41.71	$ 35.85	$ 41.31	$ 0.47
September 30, 2011	38.98	33.09	38.02	0.46
June 30, 2011	38.99	34.37	37.68	0.46
March 31, 2011	36.92	33.47	35.14	0.46

AEP common stock is traded principally on the New York Stock Exchange. As of December 31, 2012, AEP had approximately 83,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., the S&P 500 Index, and the S&P Electric Utilities Index



*$100 invested on 12/31/07 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2012	2011	2010	2009	2008
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 14,945	$ 15,116	$ 14,427	$ 13,489	$ 14,440
Operating Income	$ 2,656	$ 2,782	$ 2,663	$ 2,771	$ 2,787
Income Before Discontinued Operations and Extraordinary Items	$ 1,262	$ 1,576	$ 1,218	$ 1,370	$ 1,376
Discontinued Operations, Net of Tax	-	-	-	-	12
Income Before Extraordinary Items	1,262	1,576	1,218	1,370	1,388
Extraordinary Items, Net of Tax	-	373	-	(5)	-
Net Income	1,262	1,949	1,218	1,365	1,388
Net Income Attributable to Noncontrolling Interests	3	3	4	5	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,259	1,946	1,214	1,360	1,383
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,259	$ 1,941	$ 1,211	$ 1,357	$ 1,380
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 57,454	$ 55,670	$ 53,740	$ 51,684	$ 49,710
Accumulated Depreciation and Amortization	18,691	18,699	18,066	17,340	16,723
Total Property, Plant and Equipment – Net	$ 38,763	$ 36,971	$ 35,674	$ 34,344	$ 32,987
Total Assets	$ 54,367	$ 52,223	$ 50,455	$ 48,348	$ 45,155
Total AEP Common Shareholders' Equity	$ 15,237	$ 14,664	$ 13,622	$ 13,140	$ 10,693
Noncontrolling Interests	$ -	$ 1	$ -	$ -	$ 17
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ -	$ -	$ 60	$ 61	$ 61
Long-term Debt (a)	$ 17,757	$ 16,516	$ 16,811	$ 17,498	$ 15,983
Obligations Under Capital Leases (a)	$ 449	$ 458	$ 474 (b)	$ 317	$ 325
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations and Extraordinary Items	$ 2.60	$ 3.25	$ 2.53	$ 2.97	$ 3.40
Discontinued Operations, Net of Tax	-	-	-	-	0.03
Income Before Extraordinary Items	2.60	3.25	2.53	2.97	3.43
Extraordinary Items, Net of Tax	-	0.77	-	(0.01)	-
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 2.60	$ 4.02	$ 2.53	$ 2.96	$ 3.43
Weighted Average Number of Basic Shares Outstanding (in millions)	485	482	479	459	402
Market Price Range:					
High	$ 45.41	$ 41.71	$ 37.94	$ 36.51	$ 49.11
Low	$ 36.97	$ 33.09	$ 28.17	$ 24.00	$ 25.54
Year-end Market Price	$ 42.68	$ 41.31	$ 35.98	$ 34.79	$ 33.28
Cash Dividends Declared per AEP Common Share	$ 1.88	$ 1.85	$ 1.71	$ 1.64	$ 1.64
Dividend Payout Ratio	72.31%	46.02%	67.59%	55.41%	47.8%
Book Value per AEP Common Share	$ 31.35	$ 30.36	$ 28.32	$ 27.49	$ 26.35

(a) Includes portion due within one year.
(b) Obligations Under Capital Leases increased primarily due to capital leases under new master lease agreements for property that was previously leased under operating leases.

EXECUTIVE OVERVIEW

Company Overview

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

Our subsidiaries operate an extensive portfolio of assets including:

- Almost 37,600 megawatts of generating capacity, one of the largest complements of generation in the United States.
- Approximately 40,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 221,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 7,600 railcars, approximately 3,100 barges, 60 towboats, 25 harbor boats and a coal handling terminal with approximately 18 million tons of annual capacity). Our commercial barging operations annually transport approximately 42 million tons of coal and dry bulk commodities. Approximately 38% of the barging is for transportation of agricultural products, 30% for coal, 18% for steel and 14% for other commodities.

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the completed facility. See the "Turk Plant" section of Note 3.

Sustainable Cost Reductions

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to conduct an organizational and process optimization evaluation and a second firm to evaluate our current employee benefit programs. We recorded a charge to expense of $47 million ($30 million, net of tax) in 2012 related primarily to severance benefits. We expect to complete the final phase of the sustainable cost reduction program by the end of the first quarter of 2013. Going forward, we anticipate that this program provides a behavioral foundation upon which additional process improvement projects will be implemented as a regular business practice. At this time, we are unable to estimate the total amount to be incurred in future periods related to this initiative or to quantify the effects on future earnings, cash flows and financial condition.

Retiree Medical Contribution Changes

In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical coverage will be capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. For 2013, we estimate these changes will result in a decrease of Other Operation and Maintenance expenses of approximately $80 million.

Financing Changes

In December 2012, we retired $558 million of Parent debt with part of the proceeds of an issuance of $850 million of Senior Unsecured Notes. Expenses associated with the early retirement of debt were approximately $50 million in 2012 with annual savings of approximately $30 million per year in 2013 and 2014.

In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

Ohio Plant Impairments

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement, we performed an evaluation of the recoverability of generation assets using generating unit specific estimated future cash flows and concluded that OPCo had a material impairment of certain generation assets. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million ($185 million, net of tax) in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units and related material and supplies inventory.

Corporate Separation, Plant Transfers and Termination of Interconnection Agreement

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo’s generation assets including the transfer of OPCo’s generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and the Ohio Consumers’ Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also 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 filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo’s current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and 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 Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. 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.

In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval of the Amos Plant and Mitchell Plant transfers discussed above. Hearings at the Virginia SCC and the WVPSC are scheduled for April 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery when they file their next base rate cases.

Also in December 2012, KPCo filed a request with the KPSC for approval of the Mitchell Plant transfer discussed above. 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 and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

Our results of operations related to generation in Ohio will be largely determined by prevailing market conditions.

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP through May 2015. The ESP allowed the continuation of the fuel adjustment clause, adopted a 12% earnings threshold for the SEET and established a non-bypassable Distribution Investment Rider (DIR) effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. The capacity order, including collection of capacity costs, has been appealed to the Supreme Court of Ohio.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its deferred capacity costs and ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 3.

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. As a result, we lost approximately $235 million of gross margin in 2012 as compared to 2011. This reduction in gross margin is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs, (d) Retail Stability Rider collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation and Marketing segment which targets retail customers, both within and outside of our retail service territory. As of December 31, 2012, based upon an average annual load, approximately 51% of our Ohio load had switched to CRES providers.

Customer Demand

In comparison to 2011, cooling degree days in 2012 were down 6% in our western region and up 4% in our eastern region. Heating degree days in 2012 were down in our western and eastern regions by 36% and 15%, respectively. Our weather-normalized retail sales were down 0.7% compared to 2011. Our industrial sales declined 0.9% partially due to Ormet, a large aluminum company that lowered their production in the third quarter of 2012 by one-third. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware.

In 2013, we anticipate slight increases in retail sales in our eastern region related to shale gas development and processing and in our western region related to oil and gas extraction. We also anticipate decreases in industrial demand in our eastern region related to Ormet's lower production levels discussed above.

Significantly Excessive Earnings Test

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. In the fourth quarter of 2012, the Supreme Court of Ohio upheld the PUCO decision on the 2009 SEET filing. Subsequent testimony and legal briefs from intervenors recommended refunds of a portion of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo. See "Ohio Electric Security Plan Filing" section of Note 3.

Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the acceleration of the retirement date of Tanners Creek Plant, Units 1-3. I&M filed rebuttal testimony in May 2012 which supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve. See "2011 Indiana Base Rate Case" section of Note 3.

Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates. In December 2012, several intervenors filed opposing testimony with various recommendations. A decision from the PUCT is expected in the second quarter of 2013. See "2012 Texas Base Rate Case" section of Note 3.

Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and a hearing was conducted. The settlement provided that SWEPCo would increase Louisiana total rates by approximately $2 million annually, effective March 2013, consisting of an increase in base rates of approximately $85 million annually offset by a decrease in fuel rates of approximately $83 million annually. The proposed March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning January 2013. A decision from the LPSC is expected in the first quarter of 2013.

Cook Plant

Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant, Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. In February 2013, we signed an agreement and received payment from NEIL, the insurer, to settle the remaining claims. The settlement did not have a material impact on net income, cash flows or financial condition. See "Cook Plant, Unit 1 Fire and Shutdown" section of Note 5.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC. Several intervenors filed testimony in Indiana with various recommendations including caps on expenditures. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition. See "Cook Plant Life Cycle Management Project" section of Note 3.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. We will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. We are also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. We believe that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Recovery in Ohio will be dependent upon prevailing market conditions. If we are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2012, the AEP System had a total generating capacity of nearly 37,600 MWs, of which over 23,700 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon our estimates, investment to meet these proposed requirements ranges from approximately $4 billion to $5 billion between 2012 and 2020. These amounts include investments to convert 1,555 MWs of coal generation to natural gas capacity. If natural gas conversion is not completed, these units could be retired sooner than planned.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

Subject to the factors listed above and based upon our continuing evaluation, we have given notice to the applicable RTOs of our intent to retire the following plants or units of plants before or during 2016:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
KPCo	Big Sandy Plant, Unit 1	278
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528
Total		4,441

Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. OPCo owns 12.5% (53 MWs) of one unit at that station.

KPCo notified the KPSC of its plan to retire Big Sandy Plant, Unit 2 in early 2015 and its intention to study the conversion of Big Sandy Plant, Unit 1 to burn natural gas instead of coal.

In September 2012, based upon an agreement in principle with the Federal EPA, the State of Oklahoma and other parties, PSO filed an environmental compliance plan with the OCC to retire Units 3 and 4 of the Northeastern Station, a total of 930 MWs, in 2026 and 2016, respectively. See "Oklahoma Environmental Compliance Plan" and "Regional Haze" sections below.

In December 2012, we retired OPCo's 165 MW Conesville Plant, Unit 3.

A decline in natural gas prices, pending environmental rules and the proposed termination of the Interconnection Agreement had an adverse impact on the recoverability of the net book values of certain coal-fired units. In 2012, we recorded a $287 million pretax impairment charge for OPCo's net book value of certain plants totaling 1,870 MWs in the table above and the Beckjord and Conesville plants discussed above. See "Impairments" section of Note 6.

We are still evaluating our plans for and the timing of conversion of some of our coal units to natural gas, installing emission control equipment on other units and closure of existing units based on changes in emission requirements and demand for power. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could reduce future net income and cash flows.

Modification of the NSR Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle all claims that the AEP subsidiaries violated the NSR provisions of the CAA when they undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

The consent decree requires certain types of control equipment to be installed at Muskingum River Plant, Unit 5 and Big Sandy Plant, Unit 2 in 2015 and the two units of the Rockport Plant in 2017 and 2019. In February 2013, an agreement to modify the consent decree was reached and filed with the court. The terms of the modification include more options for the affected units (including alternative control technologies, re-fueling and/or retirement), more stringent SO_2 emission caps for the AEP System and additional mitigation measures. The Federal EPA will seek public comments on the modification prior to its entry by the court. Under the terms of the modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2015 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028. Muskingum River Plant, Unit 5 will have options to cease burning coal and retire in 2015 or cease burning coal in 2015 and complete a refueling project no later than June 2017. Big Sandy Plant, Unit 2 will have options to retrofit, retire, repower or refuel by 2015. I&M will secure an additional 200 MWs of renewable power resources by December 2014 and provide $8.5 million for additional mitigation projects.

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, we have incurred $71 million related to these environmental controls, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it would reduce future net income and cash flows. In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. See the "Modification of the NSR Litigation Consent Decree" section above and the "Rockport Plant Environmental Controls" section of Note 3.

Big Sandy 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 Unit 2 with a dry FGD system. As part of the Mitchell Plant transfer filing discussed above under "Corporate Separation, Plant Transfers and Application to Amend Sharing Agreement", 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. See "Big Sandy Plant, Unit 2 FGD System" section of Note 3.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. As of December 31, 2012, SWEPCo has incurred $11 million related to this project, including AFUDC and company overheads. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing is scheduled for March 2013. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at NES Unit 3, (b) cost recovery through 2026 of NES Units 3 and 4 net book value (combined net book value of the two units is $234 million as of December 31, 2012), (c) cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014. In January 2013, several parties filed testimony with various recommendations. A hearing is scheduled for April 2013. See "Oklahoma Environmental Compliance Plan" section of Note 3.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the District of Columbia Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The United States Court of Appeals for the District of Columbia Circuit issued an order in December 2011 staying the effective date of the rule pending judicial review. In August 2012, a panel of the United States Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. Nearly all of the states in which our power plants are located are covered by CAIR.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants (discussed in detail below) in February 2012.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO_2 emissions from affected units in that state. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the United States Court of Appeals for the District of Columbia Circuit and its fate is uncertain given recent developments in the CSAPR litigation.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new electric utility units and agreed to specific deadlines to issue proposed new source performance standards for utility boilers.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO_2, NO_x, lead and PM, and is currently reviewing the NAAQS for ozone. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting our operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In August 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in March 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the United States Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay. In August 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the CAIR until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "over control" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents filed petitions for rehearing but in January 2013, the United States Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In November 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. It is uncertain whether any of the information generated during the reconsideration process will affect the standards for existing sources.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. We are participating in petitions for review filed in the United States Court of Appeals for the District of Columbia Circuit by several organizations of which we are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. The case is proceeding on the remaining issues and briefing is scheduled to be completed by April 2013.

Regional Haze

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed to approve all of the NO_x control measures in the SIP and disapprove the SO_2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA proposed a FIP that would require these units to install technology capable of reducing SO_2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. The Federal EPA finalized the FIP in December 2011 that mirrored the proposed rule but established a five-year compliance schedule. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, we notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. Notice of the proposed settlement was published in the Federal Register in November 2012 and the comment period has closed. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement.

CO_2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO_2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO_2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources and does not apply to units whose CO_2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction. The comment period closed in June 2012. New source performance standards affect units that have not yet received permits, but complete the permitting process while the proposal is pending. The proposed standards were challenged in the United States Court of Appeals for the District of Columbia Circuit. That case was dismissed because the court determined that no final agency action had yet been taken. The Federal EPA is expected to finalize these standards in 2013.

In June 2012, the United States Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase-in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed which the court denied in December 2012. Petitioners may seek further review in the U.S. Supreme Court.

The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. Our generating units are large sources of CO_2 emissions and we will continue to evaluate the permitting obligations in light of these thresholds.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. The Federal EPA has also announced its intention to complete a risk assessment of various beneficial uses of coal ash. Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and is seeking additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act for utility facilities.

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. We submitted comments in July 2012. Issuance of a final rule is not expected until June 2013. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule is expected in 2013 and a final rule in 2014. We are unable to predict the impact of these changes but expect the costs to be significant.

Climate Change

National public policy makers and regulators in the 11 states we serve have diverse views on climate change. We are currently focused on responding to these emerging views with prudent actions, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO_2 emissions from power plants. The majority of the states where we have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power. By the end of 2012, we secured, through power purchase agreements, 1,994 MW of wind and solar power.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We participated in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, but many of these programs have been discontinued due to anticipated legislative or regulatory actions. We estimate that our 2012 emissions were approximately 122 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 5.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. Public perception may ultimately have a significant impact on future legislation and regulation that could adversely affect our ability to recover our investments in coal-fired plants.

Climate change and its resultant impact on weather patterns could modify our customers' power usage. Our customers' energy needs currently vary with weather conditions and the economy. Increased or decreased energy usage could require the acquisition or construction of more generation and transmission assets or cause early retirement of such assets. The timing and duration of extreme weather conditions may require more system backup and contribute to increased system stresses, including service interruptions and increased storm restoration costs. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales and higher margins.

To the extent climate change affects a region's economic health, it could also affect our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are outlined below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

AEP River Operations

- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The table below presents Income Before Extraordinary Item by segment for the years ended December 31, 2012, 2011 and 2010.

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Utility Operations	$ 1,299	$ 1,549	$ 1,192
Transmission Operations	43	30	9
AEP River Operations	15	45	37
Generation and Marketing	7	14	25
All Other (a)	(102)	(62)	(45)
Income Before Extraordinary Item	$ 1,262	$ 1,576	$ 1,218

(a) While not considered a reportable segment, All Other includes:
- Parent’s guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations, which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

AEP CONSOLIDATED

2012 Compared to 2011

Income Before Extraordinary Item decreased from $1,576 million in 2011 to $1,262 million in 2012 primarily due to:

- A decrease in carrying costs income due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- The 2012 impairment for certain Ohio generation plants.
- The loss of retail customers in Ohio to various CRES providers.
- A decrease in weather-related usage.
- The elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
- Expenses associated with the early retirement of Parent debt in 2012.
- Expenses related to the 2012 sustainable cost reductions.
- The 2012 adjustment of a UK windfall tax provision as a result of a recent related Supreme Court case.

These decreases were partially offset by:

- Successful rate proceedings in our various jurisdictions.
- Lower spending in 2012 as a result of our cost containment efforts.
- A 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.
- The 2011 plant impairments for Sporn Plant Unit 5 and for the FGD project at Muskingum River Plant Unit 5.
- The 2011 write-off related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- A loss incurred in 2011 related to a settlement of litigation with BOA and Enron.

Average basic shares outstanding increased to 485 million in 2012 from 482 million in 2011. Actual shares outstanding were 486 million as of December 31, 2012.

2011 Compared to 2010

Income Before Extraordinary Item increased from $1,218 million in 2010 to $1,576 million in 2011 primarily due to:

- An increase in carrying costs income due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- A decrease in expenses as a result of the 2010 cost reduction initiatives.
- Successful rate proceedings in our various jurisdictions.

These increases were partially offset by:

- The loss of retail customers in Ohio to various CRES providers.
- Various Ohio adjustments in 2011, including:
  - The plant impairments for Sporn Plant Unit 5 and for the FGD project at Muskingum River Plant Unit 5.
  - A net decrease due to unfavorable Ohio regulatory orders in 2011.
  - The recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund.
- The elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
- A 2011 write-off related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.

Average basic shares outstanding increased from 479 million in 2010 to 482 million in 2011. Actual shares outstanding were 483 million as of December 31, 2011.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross Margin represents total revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

	Years Ended December 31,		
	2012	**2011**	**2010**
		(in millions)	
Revenues	$ 13,778	$ 14,200	$ 13,792
Fuel and Purchased Electricity	4,963	5,455	4,996
Gross Margin	8,815	8,745	8,796
Other Operation and Maintenance	3,352	3,539	3,760
Asset Impairments and Other Related Charges	300	139	-
Depreciation and Amortization	1,734	1,613	1,598
Taxes Other Than Income Taxes	828	812	811
Operating Income	2,601	2,642	2,627
Interest and Investment Income	7	29	9
Carrying Costs Income	53	393	70
Allowance for Equity Funds Used During Construction	78	91	77
Interest Expense	(882)	(886)	(942)
Income Before Income Tax Expense and Equity Earnings	1,857	2,269	1,841
Income Tax Expense	560	722	651
Equity Earnings of Unconsolidated Subsidiaries	2	2	2
Income Before Extraordinary Item	$ 1,299	$ 1,549	$ 1,192

Summary of KWh Energy Sales for Utility Operations

	Years Ended December 31,		
	2012	**2011**	**2010**
	(in millions of KWhs)		
Retail:			
Residential	58,780	61,655	61,944
Commercial	50,464	50,767	50,748
Industrial	59,154	59,667	57,333
Miscellaneous	3,072	3,100	3,083
Total Retail (a)	171,470	175,189	173,108
Wholesale	41,892	40,519	32,581
Total KWhs	213,362	215,708	205,689

(a) Represents energy delivered to distribution customers.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations

	Years Ended December 31,		
	2012	**2011**	**2010**
	(in degree days)		
Eastern Region			
Actual - Heating (a)	2,382	2,794	3,222
Normal - Heating (b)	2,987	2,980	2,983
Actual - Cooling (c)	1,258	1,215	1,307
Normal - Cooling (b)	1,029	1,017	1,002
Western Region			
Actual - Heating (a)	654	1,029	1,112
Normal - Heating (b)	984	984	980
Actual - Cooling (d)	2,852	3,020	2,515
Normal - Cooling (b)	2,372	2,349	2,339

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

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Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Utility Operations Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$	1,549
Changes in Gross Margin:		
Retail Margins		23
Off-system Sales		(19)
Transmission Revenues		83
Other Revenues		(17)
Total Change in Gross Margin		70
Changes in Expenses and Other:		
Other Operation and Maintenance		187
Asset Impairments and Other Related Charges		(161)
Depreciation and Amortization		(121)
Taxes Other Than Income Taxes		(16)
Interest and Investment Income		(22)
Carrying Costs Income		(340)
Allowance for Equity Funds Used During Construction		(13)
Interest Expense		4
Total Change in Expenses and Other		(482)
Income Tax Expense		162
Year Ended December 31, 2012	$	1,299

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $23 million primarily due to the following:
  - Successful rate proceedings in our service territories, which include:
    - A $177 million rate increase for OPCo.
    - An $87 million rate increase for APCo.
    - A $17 million rate increase for I&M.
    - A $13 million rate increase for PSO.
    - An $11 million rate increase for WPCo.

      For the rate increases described above, $156 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $71 million decrease in other variable electric generation expenses.
  - A $35 million increase due to OPCo's 2012 partial reversal of a 2011 fuel provision based on an April 2012 PUCO order related to the 2009 FAC audit.
  - A $33 million decrease in recoverable PJM expenses in Ohio.
  - A $24 million write-off in 2011 related to APCo's disallowance of certain Virginia environmental costs incurred in 2009 and 2010 as a result of the November 2011 Virginia SCC order.
  - A $9 million deferral of APCo's additional wind purchase costs as a result of the June 2012 Virginia SCC fuel factor order.
  - A $9 million increase due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.

These increases were partially offset by:

- A $289 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
- A $95 million decrease in weather-related usage in our eastern and western regions primarily due to decreases of 15% and 36%, respectively, in heating degree days and a 6% decrease in cooling degree days in our western region.
- An $85 million net decrease in regulated revenue due to the elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.

- **Margins from Off-system Sales** decreased $19 million primarily due to lower market prices, lower PJM capacity payments and reduced trading and marketing margins, partially offset by higher Ohio CRES capacity revenues.
- **Transmission Revenues** increased $83 million primarily due to net rate increases in ERCOT and increased transmission revenues from Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets the lost transmission revenues included in Retail Margins above.
- **Other Revenues** decreased $17 million primarily due to a decrease in gains on miscellaneous sales, partially offset by an increase in revenues related to TCC's issuance of securitization bonds in March 2012. This increase in revenues from securitization bonds is partially offset by an increase in Depreciation and Amortization expense.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $187 million primarily due to the following:
  - A $141 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $72 million decrease in nonutility operations and distribution expenses due to prior year cost reduction measures.
  - A $70 million decrease related to the 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.
  - A $41 million decrease due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $16 million decrease in administrative and general expenses.
  - A $13 million decrease due to APCo's deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC recovered dollar-for-dollar within Gross Margin.

  These decreases were partially offset by:
  - A $44 million increase due to expenses related to the 2012 sustainable cost reductions.
  - A $42 million increase in energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $33 million increase due to the 2011 deferral of 2009 storm costs and the 2010 cost reduction initiatives as allowed by the WVPSC.
  - A $27 million increase due to the favorable 2011 asset retirement obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - A $15 million increase in storm-related expenses due to major storms in our eastern region.
  - An $11 million gain from the sale of land in January 2011.
- **Asset Impairments and Other Related Charges** increased $161 million primarily due to the following:
  - A 2012 impairment of $287 million for certain Ohio generation plants, which includes $13 million of related materials and supplies inventory.
  - A 2012 write-off of an additional $13 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap.

This increase was partially offset by:

- A 2011 write-off of $49 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- A 2011 plant impairment of $48 million for Sporn Plant Unit 5.
- A 2011 plant impairment of $42 million for FGD project at Muskingum River Plant Unit 5.

- **Depreciation and Amortization** expenses increased $121 million primarily due to the following:
  - A $58 million increase due to shortened depreciable lives for certain OPCo generating plants effective December 2011. The book value of these plants was fully impaired in November 2012.
  - A $51 million increase due to TCC's issuance of securitization bonds in March 2012. The increase in TCC's securitization related amortization is offset within Gross Margin.
  - A $48 million combined increase in depreciation for APCo and I&M primarily due to increases in depreciation rates effective February 2012 (Virginia) and April 2012 (Michigan), respectively. The majority of this increase in depreciation is offset within Gross Margin.
  - An $18 million increase in amortization primarily as a result of the Virginia Environmental Rate Adjustment Clause and the Virginia E&R surcharge, both effective February 2012. This increase in amortization is offset within Gross Margin.
  - An $11 million increase in amortization of OPCo's Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $39 million decrease due to an amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $28 million decrease due to the deferral of capacity-related depreciation costs as a result of the PUCO's July 2012 approval of OPCo's capacity rate.
  - A $23 million decrease due to OPCo's amortization of carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The equity amortization was offset by amounts recognized in Carrying Costs Income.
  - A $13 million decrease in OPCo's depreciation due to the 2011 plant impairment of Sporn Plant Unit 5.
- **Taxes Other Than Income Taxes** increased $16 million primarily due to increased property taxes as a result of increased capital investments.
- **Interest and Investment Income** decreased $22 million primarily due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- **Carrying Costs Income** decreased $340 million primarily due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Allowance for Equity Funds Used During Construction** decreased $13 million primarily due to the completion of APCo's Dresden Plant in January 2012 and I&M's nuclear fuel preparation for usage, partially offset by increases related to SWEPCo's construction of the Turk Plant.
- **Interest Expense** decreased $4 million primarily due to lower long-term interest rates.
- **Income Tax Expense** decreased $162 million primarily due to a decrease in pretax book income, partially offset by the recording of federal and state income tax adjustments.

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2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Income from Utility Operations Before Extraordinary Item
(in millions)

Year Ended December 31, 2010	$ 1,192
Changes in Gross Margin:	
Retail Margins	(139)
Off-system Sales	44
Transmission Revenues	48
Other Revenues	(4)
Total Change in Gross Margin	(51)
Changes in Expenses and Other:	
Other Operation and Maintenance	221
Asset Impairments and Other Related Charges	(139)
Depreciation and Amortization	(15)
Taxes Other Than Income Taxes	(1)
Interest and Investment Income	20
Carrying Costs Income	323
Allowance for Equity Funds Used During Construction	14
Interest Expense	56
Total Change in Expenses and Other	479
Income Tax Expense	(71)
Year Ended December 31, 2011	$ 1,549

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** decreased $139 million primarily due to the following:
  - A $132 million decrease attributable to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - An $87 million decrease in weather-related usage in our eastern region primarily due to a 13% decrease in heating degree days and a 7% decrease in cooling degree days.
  - An $84 million decrease in rate related margins for APCo due to the expiration of E&R cost recovery in Virginia.
  - A $60 million decrease due to the elimination of POLR charges, effective June 2011, in Ohio as a result of the October 2011 PUCO remand order.
  - A $51 million net decrease due to unfavorable Ohio and Virginia regulatory orders.
  - A $30 million increase in other variable electric generation expenses.

  These decreases were partially offset by:
  - Successful rate proceedings in our service territories which include:
    - A $120 million rate increase for OPCo.
    - A $63 million rate increase for APCo.
    - A $30 million rate increase for SWEPCo.
    - A $27 million rate increase for KPCo.
    - A $27 million rate increase for I&M.

    For the rate increases described above, $78 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $38 million increase in weather-related usage in our western region primarily due to a 20% increase in cooling degree days, slightly offset by a 7% decrease in heating degree days.

- A $30 million increase due to increased SWEPCo gross margin from sales to customers previously served by Valley Electric Membership Corporation (VEMCO). SWEPCo acquired VEMCO assets and began serving VEMCO customers in October 2010.
- A $14 million increase related to TCC's Transition Funding. This increase is offset by an increase in Depreciation and Amortization expenses.

- **Margins from Off-system Sales** increased $44 million primarily due to an increase in PJM capacity revenues and higher physical sales volumes, partially offset by lower trading and marketing margins.
- **Transmission Revenues** increased $48 million primarily due to net rate increases in PJM and increased transmission revenues for Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers offsets the lost transmission revenues included in Retail Margins above.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $221 million primarily due to the following:
  - A $280 million decrease due to expenses related to the cost reduction initiatives recorded in 2010.
  - A $54 million decrease due to the 2010 write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.
  - A $42 million decrease in administrative and general expenses primarily due to a decrease in fringe benefit expenses.
  - A $33 million decrease due to the 2011 deferral of 2010 costs related to storms and our cost reduction initiatives as allowed by the WVPSC.
  - A $27 million decrease due to the favorable 2011 asset retirement obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - An $11 million gain from the sale of land in January 2011.

  These decreases were partially offset by:
  - A $54 million increase in demand side management, energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $41 million increase due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $35 million increase related to the 2011 recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the approved December 2011 Ohio stipulation agreement.
  - A $33 million increase in storm-related expenses.
  - A $33 million increase in plant outage and other plant operating and maintenance expenses.
  - A $25 million increase due to the 2010 deferral of 2009 storm costs as allowed by the Virginia SCC.
- **Asset Impairments and Other Related Charges** in 2011 included the following:
  - A 2011 plant impairment of $48 million for Sporn Plant Unit 5.
  - A 2011 plant impairment of $42 million for the FGD project at Muskingum River Plant Unit 5.
  - A 2011 write-off of $49 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- **Depreciation and Amortization** expenses increased $15 million primarily due to the following:
  - A $23 million increase due to the amortization of carrying costs on deferred fuel as a result of the October 2011 Ohio POLR remand order.
  - A $20 million increase in depreciation and amortization for TCC primarily due to increased amortization of TCC's Securitized Transition Assets. This increase is partially offset by an increase in revenues within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $34 million decrease in depreciation and amortization for APCo primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia.
- **Interest and Investment Income** increased $20 million primarily due to interest income recorded in 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.

- **Carrying Costs Income** increased $323 million due to the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Allowance for Equity Funds Used During Construction** increased $14 million primarily due to construction of the Turk and Dresden Plants and various environmental upgrades, partially offset by a decrease due to the completion of the Stall Unit in June 2010.
- **Interest Expense** decreased $56 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $71 million primarily due to an increase in pretax book income, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits and by the recording of federal and state income tax adjustments.

TRANSMISSION OPERATIONS

Wholly-owned Entities

AEP Transmission Company, LLC (AEPTCo), a subsidiary of AEP, has seven wholly-owned transmission companies as follows:

AEP East Transmission Companies (all operating within PJM)

- AEP Appalachian Transmission Company, Inc. (APTCo) (covering Virginia)
- AEP Indiana Michigan Transmission Company, Inc. (IMTCo)
- AEP Kentucky Transmission Company, Inc. (KTCo)
- AEP Ohio Transmission Company, Inc. (OHTCo)
- AEP West Virginia Transmission Company, Inc. (WVTCo)

AEP West Transmission Companies (all operating within SPP)

- AEP Oklahoma Transmission Company, Inc. (OKTCo)
- AEP Southwestern Transmission Company, Inc. (SWTCo) (covering Arkansas and Louisiana)

IMTCo, OHTCo, OKTCo and WVTCo have been approved by the applicable state commissions or are operating where state approval was not necessary. APTCo has been authorized to submit projects for approval from the Virginia SCC. Applications for regulatory approvals have been filed and are currently under consideration in Arkansas, Kentucky and Louisiana.

The AEP East Transmission Companies and the AEP West Transmission Companies have FERC-approved returns on common equity of 11.49% and 11.20%, respectively, based on a capital structure of up to 50% equity. AEPSC and other AEP subsidiaries provide services to the transmission companies through service agreements.

All of the transmission companies' capital needs are provided by Parent, AEPTCo and/or the Utility Money Pool. The Utility Money Pool is used to meet the short-term borrowing needs of AEP regulated utility subsidiaries. The Utility Money Pool operates in accordance with the terms and conditions approved in regulatory orders.

In October 2012, AEPTCo completed a $250 million debt offering and immediately loaned $200 million and $50 million in proceeds to OHTCo and IMTCo, respectively. In December 2012, AEPTCo issued an additional $75 million in debt and immediately loaned the proceeds to OKTCo. AEPTCo will issue an additional $25 million in March 2013 but it is not yet determined which subsidiaries of AEPTCo will receive the proceeds.

Joint Venture Initiatives

We are currently participating in the following joint venture initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Investment at December 31, 2012	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2022	MidAmerican Energy (50%) AEP (50%)	$ 3,056,000 (a)	$ 353,654	9.96 %
Prairie Wind	Kansas	2014	Westar Energy (50%) MidAmerican Energy (25%) (b) AEP (25%) (b)	180,000	7,091	12.8 %
Pioneer	Indiana	2018 (c)	Duke Energy (50%) AEP (50%)	950,000 (c)	1,876	12.54 %
RITELine IN	Indiana	2019	Exelon (12.5%) (d) AEP (87.5%) (d)	400,000	732 (e)	11.43 %
RITELine IL	Illinois	2019	Commonwealth Edison (75%) Exelon (12.5%) (d) AEP (12.5%) (d)	1,200,000	115 (e)	11.43 %
Transource Missouri	Missouri	2017	Great Plains Energy (13.5%) (f) AEP (86.5%) (f)	445,000	823	(g)%

(a) ETT's investment in current and future projects in ERCOT over the next ten years is expected to be $3.056 billion. Future projects will be evaluated on a case-by-case basis.

(b) AEP owns 25% of Prairie Wind Transmission, LLC (Prairie Wind) through its ownership interest in ETA. ETA is a 50/50 joint venture with MidAmerican Energy and AEP.

(c) The Pioneer project consists of approximately 240 miles of new 765 kV transmission lines, which is estimated to cost $950 million at completion. In August 2012, Pioneer announced it would develop the first 66-mile segment jointly with Northern Indiana Public Service Company at a total estimated cost of $330 million, subject to regulatory approval. The projected completion date for the first 66-mile segment is 2018. The projected completion dates for the remaining segments have not been determined.

(d) AEP owns 87.5% of RITELine Indiana, LLC (RITELine IN) through its ownership interest in RITELine Transmission Development, LLC (RTD) and AEP Transmission Holding Company, LLC (AEPTHC). AEP owns 12.5% of RITELine Illinois, LLC (RITELine IL) through its ownership interest in RTD. RTD is a 50/50 joint venture with Exelon Transmission Company, LLC and AEPTHC.

(e) RITELine IN is a consolidated variable interest entity. RTD received an order from the FERC in October 2011 granting incentives for the RITELine IN and RITELine IL projects. The projects are currently under evaluation by PJM.

(f) AEP owns 86.5% of Transource Missouri through its ownership interest in Transource Energy, LLC (Transource). Transource is a joint venture with AEPTHC and Great Plains Energy formed to pursue competitive transmission projects in PJM, SPP and MISO. AEPTHC and Great Plains Energy own 86.5% and 13.5% of Transource, respectively.

(g) In August 2012, Transource Missouri requested at the FERC a base ROE of 10.6% plus incentives.

In August 2012, the PJM board cancelled the Potomac-Appalachian Transmission Highline Project (PATH Project), our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In November 2012, the FERC issued an order accepting AEP's and FirstEnergy's abandonment cost recovery filing which requested authority to recover prudently-incurred costs associated with the PATH Project. The FERC also set the issue of prudency of costs for settlement proceedings. AEP's investment in the PATH Project as of December 31, 2012 was $31 million.

For the consolidated entities within our Transmission Operations segment, we forecast approximately $700 million, excluding AFUDC, of construction expenditures for 2013. For the equity investments within our Transmission Operations segment, we forecast approximately $55 million of AEP equity contributions in 2013 to support construction expenditures and the payment of operating expenses.

2012 Compared to 2011

Income Before Extraordinary Item from our Transmission Operations segment increased from $30 million in 2011 to $43 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

2011 Compared to 2010

Income Before Extraordinary Item from our Transmission Operations segment increased from $9 million in 2010 to $30 million in 2011 primarily due to an increase in transmission investments by ETT and our wholly-owned transmission subsidiaries.

AEP RIVER OPERATIONS

2012 Compared to 2011

Income Before Extraordinary Item from our AEP River Operations segment decreased from $45 million in 2011 to $15 million in 2012 primarily due to the 2012 drought, which had significant impacts on river conditions and crop yields, resulting in reduced grain exports.

2011 Compared to 2010

Income Before Extraordinary Item from our AEP River Operations segment increased from $37 million in 2010 to $45 million in 2011 primarily due to increased coal exports, increased barge fleet size and the cost reduction initiatives in 2010, partially offset by higher fuel, maintenance and flood-related expenses.

GENERATION AND MARKETING

2012 Compared to 2011

Income Before Extraordinary Item from our Generation and Marketing segment decreased from $14 million in 2011 to $7 million in 2012 primarily due to the expiration of wind-related production tax credits in 2011 and lower gross margins at the Oklaunion Plant, partially offset by higher retail margins in PJM and higher trading margins.

2011 Compared to 2010

Income Before Extraordinary Item from our Generation and Marketing segment decreased from $25 million in 2010 to $14 million in 2011 primarily due to lower gross margins at the Oklaunion Plant.

ALL OTHER

2012 Compared to 2011

Income Before Extraordinary Item from All Other decreased from a loss of $62 million in 2011 to a loss of $102 million in 2012 primarily due to costs associated with the early retirement of debt in 2012 and the 2012 adjustment of a UK windfall tax provision as a result of a recent related Supreme Court case, partially offset by a loss incurred in 2011 related to the settlement of litigation with BOA and Enron.

2011 Compared to 2010

Income Before Extraordinary Item from All Other decreased from a loss of $45 million in 2010 to a loss of $62 million in 2011 primarily due to a loss incurred in 2011 related to the settlement of litigation with BOA and Enron and a gain on the sale of our remaining shares of Intercontinental Exchange, Inc. (ICE) in 2010, partially offset by a contribution to AEP's charitable foundation in 2010.

AEP SYSTEM INCOME TAXES

2012 Compared to 2011

Income Tax Expense decreased $214 million primarily due to a decrease in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron recorded in 2011, partially offset by the recording of federal and state income tax adjustments.

2011 Compared to 2010

Income Tax Expense increased $175 million primarily due to an increase in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits and by the recording of federal and state income tax adjustments.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31, 2012		December 31, 2011	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 17,757	52.3 %	$ 16,516	50.3 %
Short-term Debt	981	2.9	1,650	5.0
Total Debt	18,738	55.2	18,166	55.3
AEP Common Equity	15,237	44.8	14,664	44.7
Noncontrolling Interests	-	-	1	-
Total Debt and Equity Capitalization	$ 33,975	100.0 %	$ 32,831	100.0 %

Our ratio of debt-to-total capital decreased from 55.3% as of December 31, 2011 to 55.2% as of December 31, 2012 primarily due to an increase in common equity, partially offset by a net increase in debt issuances, including the March 2012 issuance of $800 million of securitization bonds.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. As of December 31, 2012, we had $3.25 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of December 31, 2012, our available liquidity was approximately $3.1 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	June 2015
Revolving Credit Facility	1,750	July 2016
Total	3,250	
Cash and Cash Equivalents	279	
Total Liquidity Sources	3,529	
Less: AEP Commercial Paper Outstanding	321	
Letters of Credit Issued	131	
Net Available Liquidity	$ 3,077	

We have credit facilities totaling $3.25 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.35 billion.

In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2012 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2012 was 0.44%.

Financing Plan

As of December 31, 2012, we have $2.2 billion of long-term debt due within one year which includes $528 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current. Also included in our long-term debt due within one year is $363 million of securitization bonds and DCC Fuel notes payable which will be repaid. We plan to refinance the majority of our other maturities due within one year.

Securitized Accounts Receivables

In 2012, we renewed our receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2013 and the remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2013 on or before its maturity.

Securitization of Regulatory Assets

In March 2012, West Virginia passed securitization legislation which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize $422 million related to APCo's December 2011 under-recovered ENEC deferral balance, other ENEC-related assets and related financing costs. In January 2013, intervenors filed testimony that recommended securitization of approximately $370 million. The differences between APCo's and WPCo's request and the intervenors' testimony represent previously approved ENEC-related deferred amounts being recovered in the ENEC over extended periods, various amounts deferred subsequent to the 2011 securitization period and related securitization financing costs. APCo and WPCo are currently in settlement discussions with intervenors.

In August 2012, OPCo filed an application with the PUCO requesting securitization of the Deferred Asset Recovery Rider (DARR) balance. As of December 31, 2012, OPCo's DARR balance was $287 million, including $135 million of unrecognized equity carrying costs. Currently, the DARR is being recovered through 2018 by a non-bypassable rider. If the application is approved and the securitization bonds are issued, the DARR will cease and will be replaced by the Deferred Asset Phase-in Rider, which will recover the securitized asset over seven years.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our revolving credit agreements. Debt as defined in the revolving credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2012, this contractually-defined percentage was 51.3%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of December 31, 2012, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of December 31, 2012, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.47 per share in January 2013. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We do not believe restrictions related to our various financing arrangements and regulatory requirements will have any significant impact on Parent's ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

We do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject us to additional collateral demands under adequate assurance clauses under our derivative and non-derivative energy contracts.

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 221	$ 294	$ 490
Net Cash Flows from Operating Activities	3,804	3,788	2,662
Net Cash Flows Used for Investing Activities	(3,391)	(2,890)	(2,523)
Net Cash Flows Used for Financing Activities	(355)	(971)	(335)
Net Increase (Decrease) in Cash and Cash Equivalents	58	(73)	(196)
Cash and Cash Equivalents at End of Period	$ 279	$ 221	$ 294

Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Net Income	$ 1,262	$ 1,949	$ 1,218
Depreciation and Amortization	1,782	1,655	1,641
Other	760	184	(197)
Net Cash Flows from Operating Activities	$ 3,804	$ 3,788	$ 2,662

Net Cash Flows from Operating Activities were $3.8 billion in 2012 consisting primarily of Net Income of $1.3 billion, $1.8 billion of noncash Depreciation and Amortization and $287 million in Asset Impairments related to certain Ohio generation assets. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. A significant change in other items includes the unfavorable impact of an increase in fuel inventory due to the mild winter weather. Deferred Income Taxes increased primarily due to provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act and an increase in tax versus book temporary differences from operations. During 2012, we also contributed $200 million to our qualified pension trust.

Net Cash Flows from Operating Activities were $3.8 billion in 2011 consisting primarily of Net Income of $1.9 billion and $1.7 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Following a Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance and the PUCT's approval of a stipulation agreement, we recorded an Extraordinary Item, Net of Tax of $373 million for the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts and the reversal of tax related regulatory credits. We also recorded $393 million in Carrying Costs Income primarily related to the Texas restructuring appeals. A significant change in other items includes the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to bonus depreciation provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act, the settlement with BOA and Enron and an increase in tax versus book temporary differences from operations. In February 2011, we paid $425 million to BOA of which $211 million was used to settle litigation with BOA and Enron. The remaining $214 million was used to acquire cushion gas as discussed in Investing Activities below. During 2011, we also contributed $450 million to our qualified pension trust.

Net Cash Flows from Operating Activities were $2.7 billion in 2010 consisting primarily of Net Income of $1.2 billion and $1.6 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Other includes a $656 million increase in securitized receivables under the application of new accounting guidance for “Transfers and Servicing” related to our sale of receivables agreement. Significant changes in other items include an increase in under-recovered fuel primarily due to the deferral of fuel under the FAC in Ohio and higher fuel costs in Oklahoma, accrued tax benefits and the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to a change in tax versus book temporary differences from operations. Accrued Taxes, Net increased primarily as a result of the receipt of a federal income tax refund of $419 million related to a net operating loss in 2009 that was carried back to 2007 and 2008. We also contributed $500 million to our qualified pension trust in 2010.

Investing Activities

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Construction Expenditures	$ (3,025)	$ (2,669)	$ (2,345)
Acquisitions of Nuclear Fuel	(107)	(106)	(91)
Acquisitions of Assets/Businesses	(94)	(19)	(155)
Acquisitions of Cushion Gas from BOA	-	(214)	-
Proceeds from Sales of Assets	18	123	187
Other	(183)	(5)	(119)
Net Cash Flows Used for Investing Activities	$ (3,391)	$ (2,890)	$ (2,523)

Net Cash Flows Used for Investing Activities were $3.4 billion in 2012 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. Acquisitions of Assets/Businesses include our March 2012 purchase of BlueStar for $70 million.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2011 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. We paid $214 million to BOA for cushion gas as part of a litigation settlement.

Net Cash Flows Used for Investing Activities were $2.5 billion in 2010 primarily due to Construction Expenditures for environmental, new generation, distribution and transmission investments. Proceeds from Sales of Assets in 2010 include $139 million for sales of Texas transmission assets to ETT.

Financing Activities

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Issuance of Common Stock, Net	$ 83	$ 92	$ 93
Issuance/Retirement of Debt, Net	544	(33)	497
Retirement of Cumulative Preferred Stock	-	(64)	-
Dividends Paid on Common Stock	(916)	(898)	(824)
Other	(66)	(68)	(101)
Net Cash Flows Used for Financing Activities	$ (355)	$ (971)	$ (335)

Net Cash Flows Used for Financing Activities in 2012 were $355 million. Our net debt issuances were $544 million. The net issuances included issuances of $1.7 billion of senior unsecured notes, $800 million of securitization bonds, $287 million of notes payable and other debt and $65 million of pollution control bonds offset by retirements of $902 million of senior unsecured and other debt notes, $315 million of junior subordinate debentures, $220 million of pollution control bonds, $206 million of securitization bonds and a decrease in short-term borrowing of $669 million. We paid common stock dividends of $916 million. See Note 13 – Financing Activities.

Net Cash Flows Used for Financing Activities in 2011 were $971 million. Our net debt retirements were $33 million. The net retirements included retirements of $727 million of senior unsecured and other debt notes, $778 million of pollution control bonds and $159 million of securitization bonds offset by issuances of $710 million of notes, $627 million of pollution control bonds and an increase in short-term borrowing of $304 million. We paid common stock dividends of $898 million and $64 million to retire all of our subsidiaries' preferred stocks.

Net Cash Flows Used for Financing Activities in 2010 were $335 million. Our net debt issuances were $497 million. The net issuances included issuances of $952 million of notes and $326 million of pollution control bonds, a $531 million increase in commercial paper outstanding and retirements of $1.6 billion of notes, $148 million of securitization bonds and $222 million of pollution control bonds. Our short-term debt securitized by receivables increased $656 million under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. We paid common stock dividends of $824 million.

The following financing activities occurred during 2012:

AEP Common Stock:

- During 2012, we issued 2.2 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $83 million.

Debt:

- During 2012, we issued approximately $2.9 billion of long-term debt, including $1.7 billion of senior notes at interest rates ranging from 1.65% to 4.78% and $800 million of securitization bonds at interest rates ranging from 0.88% to 2.85%. We also issued $65 million of pollution control revenue bonds at 2.25%, $65 million of notes payable at 4.58% and $220 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2012, we entered into $750 million of interest rate derivatives and settled $458 million of such transactions. The settlements resulted in net cash payments of $23 million. As of December 31, 2012, we had in place $1.2 billion of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2013:

- In January 2013, TCC retired $105 million of its outstanding Securitization Bonds.
- In January and February 2013, I&M retired $23 million of Notes Payable related to DCC Fuel.
- In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $3.6 billion of construction expenditures excluding equity AFUDC and capitalized interest for 2013. For 2014 and 2015, we forecast construction expenditures of $3.8 billion each year. The projected increases are generally the result of required environmental investment to comply with Federal EPA rules and additional transmission spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2013 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2013 Budgeted Construction Expenditures (in millions)
Environmental	$ 544
Generation	647
Transmission	1,286
Distribution	1,009
Other	92
Total	$ 3,578

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including reducing operational expenses and spreading risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for AEGCo and I&M are $739 million and $739 million, respectively, as of December 31, 2012.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 12. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $29 million for the remaining railcars as of December 31, 2012. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five-year renewal. As of December 31, 2012, the maximum potential loss was approximately $25 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTRACTUAL OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations as of December 31, 2012:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 981	$ -	$ -	$ -	$ 981
Interest on Fixed Rate Portion of Long-term Debt (b)	861	1,527	1,308	6,011	9,707
Fixed Rate Portion of Long-term Debt (c)	1,410	2,425	2,493	10,513	16,841
Variable Rate Portion of Long-term Debt (d)	761	182	2	-	945
Capital Lease Obligations (e)	95	144	122	244	605
Noncancelable Operating Leases (e)	302	532	452	1,034	2,320
Fuel Purchase Contracts (f)	2,631	3,971	2,906	3,097	12,605
Energy and Capacity Purchase Contracts (g)	177	359	368	2,494	3,398
Construction Contracts for Capital Assets (h)	859	1,264	1,197	1,326	4,646
Total	$ 8,077	$ 10,404	$ 8,848	$ 24,719	$ 52,048

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2012 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 13. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 13. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.11% and 2.18% as of December 31, 2012.
(e) See Note 12.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets for which we have 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.

Our $61 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2012, we expect to make contributions to our pension plans totaling $108 million in 2013. Estimated contributions of $107 million in 2014 and $107 million in 2015 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the projected benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 90.2% funded as of December 31, 2012.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. As of December 31, 2012, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	**Less Than 1 Year**	**2-3 Years**	**4-5 Years**	**After 5 Years**	**Total**
			(in millions)		
Standby Letters of Credit (a)	$ 131	$ -	$ -	$ -	$ 131
Guarantees of the Performance of Outside Parties (b)	-	-	-	115	115
Guarantees of Our Performance (c)	604	15	10	62	691
Total Commercial Commitments	$ 735	$ 15	$ 10	$ 177	$ 937

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $131 million with maturities ranging from January 2013 to April 2014. See "Letters of Credit" section of Note 5.

(b) See "Guarantees of Third-Party Obligations" section of Note 5.

(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The Small Business Jobs Act, enacted in September 2010, included a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, this act extended the time for claiming bonus depreciation and increased the deduction to 100% starting in September 2010 through 2011 and decreasing the deduction to 50% for 2012. The American Taxpayer Relief Act of 2012 provided for the extension of several business and energy industry tax deductions and credits, including the one-year extension of the 50% bonus depreciation to 2013.

The enacted provisions had no material impact on net income, financial condition or cash flows in 2012, but are expected to result in material future cash flow benefits.

CYBER SECURITY

Cyber security presents a heightened risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or to our system are potentially disruptive to people, property and commerce and create risk for our business, our investors and our customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support the functions in cyber security as well as redefine how the government interfaces with critical infrastructure, such as the electric grid. We already operate under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that will be developed through this executive order will be reviewed by the FERC. We expect to participate in the process and will share best practices already in place. We protect our critical cyber assets, such as our data centers and transmission operations centers and business network, using multiple layers of cyber security and authentication. We constantly scan the system for risks or threats.

Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, we continually assess our own cyber security tools and processes to determine where we might need to strengthen our defenses.

In recent years, we have taken several steps to enhance our capabilities for identifying risks or threats. AEP became the first utility in the country to build a Cyber Security Operations Center. Funding was included as part of a larger American Recovery and Reinvestment Act Department of Energy Smart Grid Demonstration Project grant. This facility is designed as a pilot cyber threat and information-sharing center specifically for the electric sector.

We have partnered with a nonaffiliated entity to leverage their experience and technical capabilities, which were developed through their work with the U.S. Department of Defense. We work with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other and with the Department of Homeland Security. We also worked with a nonaffiliated entity to conduct several seminars in 2011 about recognizing and investigating cyber vulnerabilities. Through these types of efforts, we are working to protect AEP while helping our industry advance its cyber security capabilities.

In March 2012, we signed a cooperative research and development agreement with the Department of Homeland Security's Office of Cyber Security and Communications, further enhancing our ability to directly exchange information about cyber threats. In addition, we continue to partner with a number of federal and industry groups to advance the national capabilities of cyber security. Among them is the U.S. Department of Energy, where we are working on several pilot projects covering advanced cyber security and assessment tools.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

Our 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.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of expense and income recognition with regulated revenues. We also record liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Similarly, we record regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 4 for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues for our Utility Operations segment were $5 million, $(81) million and $46 million for the years ended December 31, 2012, 2011 and 2010, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Utility Operations segment were $473 million and $468 million as of December 31, 2012 and 2011, respectively.

In March 2012, our Generation and Marketing segment acquired an independent retail electric supplier. The change in unbilled electric utility revenues for our Generation and Marketing segment was $31 million for the year ended December 31, 2012. Accrued unbilled revenues for the Generation and Marketing segment were $38 million as of December 31, 2012.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation less the current month's billed KWh plus the prior month's unbilled KWh. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWh to the current month and previous month, on a cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWh. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We calculate credit adjustments on our risk management contracts using estimated default probabilities and recovery rates relative to our counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, we assess hedge effectiveness and evaluate a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 9 and 10. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held-and-used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of an impairment charge could be offset by the establishment of a regulatory asset if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions of the use of the asset. We perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of an asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). Additionally, we entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide health and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively referred to as the 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. See Note 7 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost of the Plans:

	Years Ended December 31,		
Net Periodic Benefit Cost	**2012**	**2011**	**2010**
		(in millions)	
Pension Plans	$ 134	$ 118	$ 141
Postretirement Plans	89	73	111

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2013, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets and changes in tax rates which affect a portion of the Postretirement Plans' assets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 6.5% for the Qualified Plan and 7% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table.

	Pension Plans		Other Postretirement Benefit Plans	
	2013 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2013 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	40 %	9.00 %	66 %	8.60 %
Fixed Income	50 %	4.00 %	33 %	3.50 %
Other Investments	10 %	8.80 %	-%	- %
Cash and Cash Equivalents	-%	-%	1 %	1.50 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 6.5% and 7% are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 13.8% and 8.1% for the years ended December 31, 2012 and 2011, respectively. The Postretirement Plans' assets had an actual gain of 15.4% and 0.4% for the years ended December 31, 2012 and 2011, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income 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 based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2012, we had cumulative gains of approximately $302 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which 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. The discount rate as of December 31, 2012 under this method was 3.95% for the Qualified Plan, 3.8% for the Nonqualified Plans and 3.95% for the Postretirement Plans. Due to the effect of the unrecognized actuarial gains and based on an expected rate of return on the Pension Plans' assets of 6.5%, discount rates of 3.95% and 3.8% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $175 million, $131 million and $102 million in 2013, 2014 and 2015, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 7%, a discount rate of 3.95% and various other assumptions, we estimate credits will approximate $15 million, $19 million and $25 million in 2013, 2014 and 2015, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical costs will be capped reducing our future exposure to medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. This change will reduce costs of the plan beginning in 2013 as shown by the estimated credits for Postretirement Plans in the previous paragraph.

The value of the Pension Plans' assets increased to $4.7 billion as of December 31, 2012 from $4.3 billion as of December 31, 2011 primarily due to investment returns and $200 million of company contributions. During 2012, the Qualified Plan paid $367 million and the Nonqualified Plans paid $16 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.6 billion as of December 31, 2012 from $1.4 billion as of December 31, 2011 primarily due to investment returns and contributions by the company and the participants. The Postretirement Plans paid $151 million in benefits to plan participants during 2012.

Nature of Estimates Required

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		**Other Postretirement Benefit Plans**	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
		(in millions)		
Effect on December 31, 2012 Benefit Obligations				
Discount Rate	$ (272)	$ 300	$ (105)	$ 116
Compensation Increase Rate	12	(11)	NA	NA
Cash Balance Crediting Rate	39	(35)	NA	NA
Health Care Cost Trend Rate	NA	NA	42	(53)
Effect on 2012 Periodic Cost				
Discount Rate	(17)	18	(11)	12
Compensation Increase Rate	4	(4)	NA	NA
Cash Balance Crediting Rate	11	(10)	NA	NA
Health Care Cost Trend Rate	NA	NA	19	(17)
Expected Return on Plan Assets	(22)	22	(7)	7

NA Not applicable.

ACCOUNTING PRONOUNCEMENTS

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, coal and emission allowance trading and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk as we occasionally procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

We employ risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. We engage in risk management of power, coal and natural gas and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2011:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2012

	Utility Operations	Generation and Marketing	Total
		(in millions)	
Total MTM Risk Management Contract Net Assets as of December 31, 2011	$ 59	$ 132	$ 191
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	-	(2)	(2)
Fair Value of New Contracts at Inception When Entered During the Period (a)	5	18	23
Acquisition of Supply Contracts (b)	-	(25)	(25)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	3	5	8
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	1	-	1
Total MTM Risk Management Contract Net Assets as of December 31, 2012	$ 68	$ 128	196
Commodity Cash Flow Hedge Contracts			(12)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts			(37)
Collateral Deposits			43
Total MTM Derivative Contract Net Assets as of December 31, 2012			$ 190

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Reflects liabilities associated with the initial fair value of supply contracts from the BlueStar acquisition in March 2012.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(d) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our 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. We use Moody's Investors Service, Standard & 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.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2012, our credit exposure net of collateral to sub investment grade counterparties was approximately 6.5%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2012, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 643	$ -	$ 643	2	$ 267
Split Rating	3	2	1	1	1
Noninvestment Grade	1	1	-	-	-
No External Ratings:					
Internal Investment Grade	98	-	98	3	36
Internal Noninvestment Grade	62	10	52	1	34
Total as of December 31, 2012	$ 807	$ 13	$ 794	7	$ 338
Total as of December 31, 2011	$ 960	$ 19	$ 941	5	$ 348

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2012, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the trading portfolio for the periods indicated:

VaR Model

Twelve Months Ended December 31, 2012				Twelve Months Ended December 31, 2011			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 1	$ -	$ -	$ -	$ 2	$ -	$ -

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last four years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2012 and 2011, the estimated EaR on our debt portfolio for the following twelve months was $42 million and $29 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2012 and 2011, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2012. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2012 and 2011, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2012, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 26, 2013 expressed an unqualified opinion on the Company's internal control over financial reporting.

Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2012, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on the criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2012 of the Company and our report dated February 26, 2013 expressed an unqualified opinion on those financial statements.

Deloitte & Touche LLP

Columbus, Ohio
February 26, 2013

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2012. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2012.

AEP's independent registered public accounting firm has issued an attestation report on AEP's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2012, 2011 and 2010
(in millions, except per-share and share amounts)

	Years Ended December 31,		
	2012	2011	2010
REVENUES			
Utility Operations	$ 13,677	$ 14,091	$ 13,687
Other Revenues	1,268	1,025	740
TOTAL REVENUES	14,945	15,116	14,427
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,111	4,421	4,029
Purchased Electricity for Resale	1,169	1,191	1,000
Other Operation	2,962	2,868	3,132
Maintenance	1,115	1,236	1,142
Asset Impairments and Other Related Charges	300	139	-
Depreciation and Amortization	1,782	1,655	1,641
Taxes Other Than Income Taxes	850	824	820
TOTAL EXPENSES	12,289	12,334	11,764
OPERATING INCOME	2,656	2,782	2,663
Other Income (Expense):			
Interest and Investment Income	8	27	38
Carrying Costs Income	53	393	70
Allowance for Equity Funds Used During Construction	93	98	77
Interest Expense	(988)	(933)	(999)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,822	2,367	1,849
Income Tax Expense	604	818	643
Equity Earnings of Unconsolidated Subsidiaries	44	27	12
INCOME BEFORE EXTRAORDINARY ITEM	1,262	1,576	1,218
EXTRAORDINARY ITEM, NET OF TAX	-	373	-
NET INCOME	1,262	1,949	1,218
Net Income Attributable to Noncontrolling Interests	3	3	4
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,259	1,946	1,214
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,259	$ 1,941	$ 1,211
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	484,682,469	482,169,282	479,373,306
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 2.60	$ 3.25	$ 2.53
Extraordinary Item, Net of Tax	-	0.77	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	485,084,694	482,460,328	479,601,442
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 2.60	$ 3.25	$ 2.53
Extraordinary Item, Net of Tax	-	0.77	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.60	$ 4.02	$ 2.53
CASH DIVIDENDS DECLARED PER SHARE	$ 1.88	$ 1.85	$ 1.71

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31,		
	2012	**2011**	**2010**
Net Income	$ 1,262	$ 1,949	$ 1,218
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $8, $18 and $14 in 2012, 2011 and 2010, Respectively	(15)	(34)	26
Securities Available for Sale, Net of Tax of $1, $1 and $4 in 2012, 2011 and 2010, Respectively	2	(2)	(8)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $16, $13 and $12 in 2012, 2011 and 2010, Respectively	31	24	22
Pension and OPEB Funded Status, Net of Tax of $62, $41 and $25 in 2012, 2011 and 2010, Respectively	115	(77)	(47)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	133	(89)	(7)
TOTAL COMPREHENSIVE INCOME	1,395	1,860	1,211
Total Comprehensive Income Attributable to Noncontrolling Interests	3	3	4
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,392	1,857	1,207
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	5	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,392	$ 1,852	$ 1,204

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	AEP Common Shareholders						
	Common Stock				Accumulated Other		
	Shares	Amount	Paid-in Capital	Retained Earnings	Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2009	498	$ 3,239	$ 5,824	$ 4,451	$ (374)	$ -	$ 13,140
Issuance of Common Stock	3	18	75				93
Common Stock Dividends				(820)		(4)	(824)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			5				5
Subtotal – Equity							12,411
Net Income				1,214		4	1,218
Other Comprehensive Loss					(7)		(7)
TOTAL EQUITY – DECEMBER 31, 2010	501	3,257	5,904	4,842	(381)	-	13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends				(894)		(4)	(898)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Loss on Reacquired Preferred Stock			(4)				(4)
Capital Stock Expense			(16)				(16)
Other Changes in Equity			11	(2)		2	11
Subtotal – Equity							12,805
Net Income				1,946		3	1,949
Other Comprehensive Loss					(89)		(89)
TOTAL EQUITY – DECEMBER 31, 2011	504	3,274	5,970	5,890	(470)	1	14,665
Issuance of Common Stock	2	15	68				83
Common Stock Dividends				(913)		(3)	(916)
Other Changes in Equity			11			(1)	10
Subtotal – Equity							13,842
Net Income				1,259		3	1,262
Other Comprehensive Income					133		133
TOTAL EQUITY – DECEMBER 31, 2012	506	$ 3,289	$ 6,049	$ 6,236	$ (337)	$ -	$ 15,237

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2012 and 2011
(in millions)

	December 31, 2012	December 31, 2011
CURRENT ASSETS		
Cash and Cash Equivalents	$ 279	$ 221
Other Temporary Investments (December 31, 2012 and 2011 Amounts Include $311 and $281, Respectively, Related to Transition Funding and EIS)	324	294
Accounts Receivable:		
Customers	685	690
Accrued Unbilled Revenues	195	106
Pledged Accounts Receivable - AEP Credit	856	920
Miscellaneous	171	150
Allowance for Uncollectible Accounts	(36)	(32)
Total Accounts Receivable	1,871	1,834
Fuel	844	657
Materials and Supplies	675	635
Risk Management Assets	191	193
Regulatory Asset for Under-Recovered Fuel Costs	88	65
Margin Deposits	76	67
Prepayments and Other Current Assets	241	216
TOTAL CURRENT ASSETS	4,589	4,182
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	26,279	24,938
Transmission	9,846	9,048
Distribution	15,565	14,783
Other Property, Plant and Equipment (Including Nuclear Fuel and Coal Mining)	3,945	3,780
Construction Work in Progress	1,819	3,121
Total Property, Plant and Equipment	57,454	55,670
Accumulated Depreciation and Amortization	18,691	18,699
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	38,763	36,971
OTHER NONCURRENT ASSETS		
Regulatory Assets	5,106	6,026
Securitized Transition Assets	2,117	1,627
Spent Nuclear Fuel and Decommissioning Trusts	1,706	1,592
Goodwill	91	76
Long-term Risk Management Assets	368	403
Deferred Charges and Other Noncurrent Assets	1,627	1,346
TOTAL OTHER NONCURRENT ASSETS	11,015	11,070
TOTAL ASSETS	$ 54,367	$ 52,223

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2012 and 2011
(dollars in millions)

	December 31, 2012	December 31, 2011
CURRENT LIABILITIES		
Accounts Payable	$ 1,169	$ 1,095
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	657	666
Other Short-term Debt	324	984
Total Short-term Debt	981	1,650
Long-term Debt Due Within One Year (December 31, 2012 and 2011 Amounts Include $367 and $293, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	2,171	1,433
Risk Management Liabilities	155	150
Customer Deposits	316	289
Accrued Taxes	747	717
Accrued Interest	269	279
Regulatory Liability for Over-Recovered Fuel Costs	47	8
Other Current Liabilities	968	990
TOTAL CURRENT LIABILITIES	6,823	6,611
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2012 and 2011 Amounts Include $2,227 and $1,674, Respectively, Related to Transition Funding, DCC Fuel and Sabine)	15,586	15,083
Long-term Risk Management Liabilities	214	195
Deferred Income Taxes	9,252	8,227
Regulatory Liabilities and Deferred Investment Tax Credits	3,544	3,195
Asset Retirement Obligations	1,696	1,472
Employee Benefits and Pension Obligations	1,075	1,801
Deferred Credits and Other Noncurrent Liabilities	940	974
TOTAL NONCURRENT LIABILITIES	32,307	30,947
TOTAL LIABILITIES	39,130	37,558
Rate Matters (Note 3)		
Commitments and Contingencies (Note 5)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2012	2011
Shares Authorized	600,000,000	600,000,000
Shares Issued	506,004,962	503,759,460

	2012	2011
(20,336,592 Shares were Held in Treasury as of December 31, 2012 and 2011)	3,289	3,274
Paid-in Capital	6,049	5,970
Retained Earnings	6,236	5,890
Accumulated Other Comprehensive Income (Loss)	(337)	(470)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	15,237	14,664
Noncontrolling Interests	-	1
TOTAL EQUITY	15,237	14,665
TOTAL LIABILITIES AND EQUITY	$ 54,367	$ 52,223

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2012, 2011 and 2010
(in millions)

	Years Ended December 31, 2012	2011	2010
OPERATING ACTIVITIES			
Net Income	$ 1,262	$ 1,949	$ 1,218
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,782	1,655	1,641
Deferred Income Taxes	636	794	809
Gain on Settlement with BOA and Enron	-	(51)	-
Settlement of Litigation with BOA and Enron	-	(211)	-
Extraordinary Item, Net of Tax	-	(373)	-
Asset Impairments and Other Related Charges	300	139	-
Carrying Costs Income	(53)	(393)	(70)
Allowance for Equity Funds Used During Construction	(93)	(98)	(77)
Mark-to-Market of Risk Management Contracts	57	37	30
Amortization of Nuclear Fuel	136	137	139
Pension Contributions to Qualified Plan Trust	(200)	(450)	(500)
Property Taxes	(19)	(15)	(21)
Fuel Over/Under-Recovery, Net	157	(25)	(253)
Change in Other Noncurrent Assets	(236)	(112)	(89)
Change in Other Noncurrent Liabilities	127	307	202
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(16)	107	(866)
Fuel, Materials and Supplies	(224)	176	221
Accounts Payable	(60)	(44)	(36)
Accrued Taxes, Net	174	193	179
Other Current Assets	(3)	37	73
Other Current Liabilities	77	29	62
Net Cash Flows from Operating Activities	3,804	3,788	2,662
INVESTING ACTIVITIES			
Construction Expenditures	(3,025)	(2,669)	(2,345)
Change in Other Temporary Investments, Net	(27)	8	(4)
Purchases of Investment Securities	(1,047)	(1,321)	(1,918)
Sales of Investment Securities	988	1,379	1,817
Acquisitions of Nuclear Fuel	(107)	(106)	(91)
Acquisitions of Assets/Businesses	(94)	(19)	(155)
Acquisition of Cushion Gas from BOA	-	(214)	-
Proceeds from Sales of Assets	18	123	187
Other Investing Activities	(97)	(71)	(14)
Net Cash Flows Used for Investing Activities	(3,391)	(2,890)	(2,523)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	83	92	93
Issuance of Long-term Debt	2,856	1,328	1,270
Commercial Paper and Credit Facility Borrowings	25	488	565
Change in Short-term Debt, Net	(654)	744	770
Retirement of Long-term Debt	(1,643)	(1,665)	(1,993)
Retirement of Cumulative Preferred Stock	-	(64)	-
Commercial Paper and Credit Facility Repayments	(40)	(928)	(115)
Principal Payments for Capital Lease Obligations	(71)	(71)	(95)
Dividends Paid on Common Stock	(916)	(898)	(824)
Dividends Paid on Cumulative Preferred Stock	-	(2)	(3)
Other Financing Activities	5	5	(3)
Net Cash Flows Used for Financing Activities	(355)	(971)	(335)
Net Increase (Decrease) in Cash and Cash Equivalents	58	(73)	(196)
Cash and Cash Equivalents at Beginning of Period	221	294	490
Cash and Cash Equivalents at End of Period	$ 279	$ 221	$ 294

See Notes to Consolidated Financial Statements beginning on page 54.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Our principal business is the generation, transmission and distribution of electric power. The subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We provide electric supply for residential, commercial and industrial customers in Ohio, Illinois and other deregulated electricity markets and also provide energy management solutions throughout the United States, including energy efficiency services through our independent retail electric supplier.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, our operations include nonregulated wind farms and barging operations.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our 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 our 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 state regulatory commissions also regulate certain intercompany transactions under various orders and 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 and wholesale power transactions. Our wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. Our wholesale power transactions in the SPP region are cost-based due to the FERC's finding that PSO and SWEPCo have market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by Texas Retail Electric Providers (REPs). Through our nonregulated subsidiaries, we enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. We have no active REPs in ERCOT.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia and I&M's retail transmission rates in Michigan are based on formula rates included in the PJM OATT that are cost-based. Although TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for our seven wholly-owned transmission subsidiaries within our Transmission Operations segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the CSW Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement, the Transmission Coordination 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.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and VIEs of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on the balance sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. We have ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and our proportionate share of the assets and liabilities are reflected on the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our 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," we record 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. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, we discontinued the application of "Regulated Operations" accounting treatment for the generation portion of our business in Texas for TNC. OPCo applies "Regulated Operations" accounting treatment only to specifically approved portions of its generation business consisting of fuel and capacity costs.

Use of Estimates

The preparation of these financial statements in conformity with GAAP 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, goodwill, intangible and 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 include temporary cash investments with original maturities of three months or less.

Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds, marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 10.

Inventory

Fossil fuel inventories are generally carried at average cost. Materials and supplies inventories are carried at average cost.

Accounts Receivable

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

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled 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 I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables related to our risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For the wires business of TCC and TNC, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. 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.

Emission Allowances

In regulated jurisdictions including Ohio through December 31, 2014, we record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. In Ohio, we record allowances expected to be consumed subsequent to December 31, 2014 at the lower of cost or market when our allowances are no longer included in the FAC due to energy auctions of SSO load. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on the balance sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on the statements of income at an average cost. We record allowances held for speculation in Prepayments and Other Current Assets on the balance sheets. We report the purchases and sales of allowances in the Operating Activities section of the statements of cash flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on the statements of income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. 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 for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for our rate-regulated operations 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 regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain our 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 held-for-sale 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. Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

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.

Nonregulated

Our nonregulated operations generally follow the policies of our rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. For nonregulated plant assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

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. For nonregulated operations, including generating assets owned by OPCo and certain generating assets in Arkansas and Texas, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest". We record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

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. Our market risk oversight staff independently monitors our 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 our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer.

For our 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. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations 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 our contracts being classified as Level 3 is the inability to substantiate our energy price curves in the market. A significant portion of our Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the benefit plan and nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments 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 Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current 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 state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Ohio (beginning in 2012 through the ESP related to non-auction standard service offer load served) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia for APCo are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) for OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. In West Virginia for APCo, all of the profits from off-system sales are given to customers through the FAC. None of the profits from off-system sales are given to customers through the FAC in Ohio for OPCo. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan (all areas of Michigan beginning in December 2010) for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

Our 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, we record them as assets on the balance sheets. We test 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, we write off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. For regulated and nonregulated operations, we recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

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. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as 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 Purchased Electricity for Resale on the statements of income. Other RTOs in which we participate 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 Purchased Electricity for Resale 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 Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, we record 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 where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, coal, natural gas and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our 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. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use 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. We include unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on the statements of income on a net basis. In jurisdictions subject to cost-based regulation, we defer unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on the balance sheets as Risk Management Assets or Liabilities as appropriate.

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). We initially record 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, we subsequently reclassify 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. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on the statements of income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 9.

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulatory jurisdictions, we defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes 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), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Government Grants

For APCo's commercial scale carbon capture and sequestration facility at the Mountaineer Plant and OPCo's gridSMART® demonstration program, APCo and OPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. In addition, AEP built a cyber security operations center that will be used to enhance the capabilities for identifying cyber risks or threats, which was also partially funded by the gridSMART® demonstration grant for OPCo's incurred costs. These reimbursements result in the reduction of Other Operation and Maintenance expenses on the statements of income or a reduction in Construction Work in Progress on the balance sheets.

Debt

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on the statements of income.

We defer debt discount or premium and debt issuance expenses and amortize 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. We include the net amortization expense in Interest Expense on the statements of income.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our 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. We regularly review the actual asset allocations and periodically rebalance 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 our benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

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

The 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, our 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. Our 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.

We participate 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. We lend 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.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company 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.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 5 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in our equity section. Our components of AOCI as of December 31, 2012 and 2011 are shown in the following table:

Components	December 31, 2012	December 31, 2011
	(in millions)	
Cash Flow Hedges, Net of Tax	$ (38)	$ (23)
Securities Available for Sale, Net of Tax	4	2
Amortization of Pension and OPEB Deferred Costs, Net of Tax	112	81
Pension and OPEB Funded Status, Net of Tax	(415)	(530)
Total	$ (337)	$ (470)

Stock-Based Compensation Plans

As of December 31, 2012, we had stock options, performance units and restricted stock units outstanding under The Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in April 2010.

We maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

In January 2006, we adopted accounting guidance for “Compensation - Stock Compensation” which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2012, 2011 and 2010 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for “Compensation - Stock Compensation” requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2012, 2011 and 2010, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director’s stock units. See Note 14 for additional discussion.

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

Amounts Attributable to AEP Common Shareholders	2012	2011	2010
		Years Ended December 31, (in millions)	
Income Before Extraordinary Item	$ 1,259	$ 1,568	$ 1,211
Extraordinary Item, Net of Tax	-	373	-
Net Income	$ 1,259	$ 1,941	$ 1,211

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on the statements of income:

	2012		2011		2010	
	Years Ended December 31, (in millions, except per share data)					
		$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,259		$ 1,941		$ 1,211	
Weighted Average Number of Basic Shares Outstanding	484.7	$ 2.60	482.2	$ 4.02	479.4	$ 2.53
Weighted Average Dilutive Effect of:						
Performance Share Units	-	-	-	-	0.1	-
Stock Options	-	-	0.1	-	-	-
Restricted Stock Units	0.4	-	0.2	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	485.1	$ 2.60	482.5	$ 4.02	479.6	$ 2.53

Options to purchase 136,250 shares of common stock as of December 31, 2010 were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive. There were no antidilutive shares outstanding as of December 31, 2012 and 2011.

OPCo Revised Depreciation Rates

Effective December 1, 2011, we revised book depreciation rates for certain of OPCo's generating plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

In the fourth quarter of 2012, OPCo impaired certain generating units, including those discussed above (see Note 6). As a result of this impairment of the full book value of these assets, OPCo ceased depreciation on these generating units effective December 1, 2012.

Supplementary Related Party Information

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2012, AEP's ownership and investment in OVEC were 43.47% and $4.4 million, respectively.

OVEC's owners are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. In 2011, the intercompany power agreement was extended until June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generating plants. As of December 31, 2012, OVEC completed financing of $1.4 billion required for these environmental projects through debt issuances. As of December 31, 2012, one plant was operating with new environmental controls and the other plant is scheduled to be operational with new environmental controls during the second quarter of 2013.

The following details related party transactions for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
Related Party Transactions	**2012**	**2011**	**2010**
		(in millions)	
AEP Consolidated Revenues – Utility Operations:			
OVEC	$ -	$ -	$ (20)(a)
AEP Consolidated Revenues – Other Revenues:			
OVEC – Barging and Other Transportation Services	30	37	29
AEP Consolidated Expenses – Purchased Electricity for Resale:			
OVEC	273	383 (b)	302 (b)

(a) The parties to the Interconnection Agreement purchased power from OVEC to serve off-system sales through an agreement that began in January 2010 and ended in June 2010.
(b) The parties to the Interconnection Agreement purchased power from OVEC to serve retail sales in 2011 and 2010. The total amount reported in 2011 and 2010 includes $66 million and $10 million, respectively, related to these agreements.

Supplementary Cash Flow Information

	Years Ended December 31,		
Cash Flow Information	**2012**	**2011**	**2010**
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 931	$ 900	$ 958
Income Taxes	(82)	(118)	(268)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	63	54	225
Construction Expenditures Included in Current Liabilities as of December 31,	439	380	267
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	35	1	-
Assumption of Liabilities Related to Acquisitions	56	-	-
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	30	-	-

2. EXTRAORDINARY ITEM

TCC Texas Restructuring

In February 2006, the PUCT issued an order that denied recovery of capacity auction true-up amounts. Based on the February 2006 PUCT order, TCC recorded the disallowance as a $421 million ($273 million, net of tax) extraordinary loss in the December 31, 2005 financial statements. In July 2011, the Supreme Court of Texas reversed the PUCT's February 2006 disallowance of capacity auction true-up amounts and remanded for reconsideration the treatment of certain tax balances under normalization rules. Based upon the Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance, TCC recorded a pretax gain of $421 million ($273 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

Following a remand proceeding, the PUCT allowed TCC to retain contested tax balances in full satisfaction of its true-up proceeding, including carrying charges. Based upon the PUCT order, TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) and the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

3. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

OPCo Rate Matters

Ohio Electric Security Plan Filing

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of December 31, 2012, OPCo's net deferred fuel balance was $519 million, excluding unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing, which resulted in a write-off in 2010 and a subsequent refund to customers during 2011. The IEU and the Ohio Energy Group filed appeals with the Supreme Court of Ohio challenging the PUCO's SEET decision. In December 2012, the Supreme Court of Ohio issued an order which rejected all of the intervenors' challenges and affirmed the PUCO decision.

The 2009 SEET order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another similar project by the end of 2013.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. The PUCO approved OPCo's request to file the 2011 SEET one month after the PUCO issues an order on the 2010 SEET. Management does not currently believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo and in 2012 for OPCo.

Management is unable to predict the outcome of the unresolved litigation discussed above. If these proceedings result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

January 2012 – May 2016 ESP as Rejected by the PUCO

In December 2011, the PUCO approved an ESP modified stipulation which established a SSO pricing for generation. Various parties filed for rehearing with the PUCO requesting that the PUCO reconsider adoption of the modified stipulation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates. Those rates remained in effect until the new ESP was approved in August 2012. See the "June 2012 – May 2015 ESP Including Capacity Charge" section below.

As a result of the PUCO's rejection of the modified stipulation, OPCo reversed a $35 million obligation to contribute to the Partnership with Ohio and the Ohio Growth Fund and an $8 million regulatory asset for 2011 storm damage, both originally recorded in 2011.

As directed by the February 2012 order, OPCo filed revised tariffs with the PUCO to implement the provisions of the 2011 ESP. Included in the revised tariffs was the Phase-In Recovery Rider (PIRR) to recover deferred fuel costs as authorized under the 2009 – 2011 ESP order. In March 2012, the PUCO issued an order that directed OPCo to file new revised tariffs removing the PIRR and stated that its recovery would be addressed in a future proceeding. OPCo implemented the new revised tariffs in March 2012. In March 2012, OPCo resumed recording a weighted average cost of capital return on the deferred fuel balance in accordance with the 2009 - 2011 ESP order. OPCo also filed a request for rehearing of the March 2012 order relating to the PIRR, which the PUCO denied but provided that all of the substantive concerns and issues raised would be addressed in a separate PIRR docket.

In August 2012, the PUCO ordered implementation of PIRR rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. The August 2012 order was upheld on rehearing by the PUCO in October 2012. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio claiming a long-term debt rate modified the previously adjudicated ESP order, which granted a weighted average cost of capital rate. The IEU and the Ohio Consumers' Counsel also filed appeals at the Supreme Court of Ohio in November 2012 arguing that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues and reduced carrying costs due to an accumulated deferred income tax credit. See the "2009 – 2011 ESP" section above. These appeals could reduce OPCo's net deferred fuel balance up to the total balance, which would reduce future net income and cash flows. A decision from the Supreme Court of Ohio is pending.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015, adopted a 12% earnings threshold for the SEET and allowed the continuation of the fuel adjustment clause. Further, the ESP established a non-bypassable Distribution Investment Rider effective September 2012 through May 2015 to recover, with certain caps, post-August 2010 distribution investment. The ESP also maintained recovery of several previous ESP riders and required OPCo to contribute $2 million per year during the ESP to the Ohio Growth Fund. In addition, the PUCO approved a storm damage recovery mechanism.

As part of the ESP decision, the PUCO ordered OPCo to conduct an energy-only auction for 10% of the SSO load with delivery beginning six months after the receipt of final orders in both the ESP and corporate separation cases and extending through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning June 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $20/MW day through May 2013. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 PUCO ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is intended to provide approximately $500 million over the ESP period and will be collected from customers at $3.50/MWh through May 2014 and $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the deferred capacity costs. As of December 31, 2012, OPCo recorded $66 million of incurred deferred capacity costs, including debt carrying costs, in Regulatory Assets on the balance sheet. In August 2012, the IEU filed an action with the Supreme Court of Ohio stating, among other things, that OPCo's collection of its capacity costs is illegal. In September 2012, OPCo and the PUCO filed motions to dismiss the IEU's action. If OPCo is ultimately not permitted to fully collect its deferred capacity costs, it would reduce future net income and cash flows and impact financial condition. A decision from the Supreme Court of Ohio is pending.

In January 2013, the PUCO issued its Order on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and costs would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket. If OPCo is ultimately not permitted to fully collect its ESP rates, including the RSR, it would reduce future net income and cash flows and impact financial condition.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets at net book value to AEPGenCo. AEPGenCo will also assume the associated generation liabilities. In December 2012, the PUCO granted the IEU and Ohio Consumers' Counsel requests for rehearing for the purpose of further consideration and those requests remain pending.

Also in October 2012, filings at the FERC were submitted related to corporate separation. See the "Corporate Separation and Termination of Interconnection Agreement" section below under FERC Rate Matters. Our results of operations related to generation in Ohio will be largely determined by prevailing market conditions.

2011 Ohio Distribution Base Rate Case

In December 2011, the PUCO approved a stipulation which provided for no change in distribution rates and a new rider for a $15 million annual credit to residential ratepayers due principally to the inclusion of the rate base distribution investment in the Distribution Investment Rider (DIR) as approved in December 2011 by the modified stipulation in the ESP proceeding. However, when the February 2012 PUCO order rejected the ESP modified stipulation, collection of the DIR terminated. In August 2012, the PUCO approved a new DIR as part of the June 2012 – May 2015 ESP proceeding. The DIR is capped at $86 million in 2012, $104 million in 2013, $124 million in 2014 and $52 million for the period January through May 2015, for a total of $366 million.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. If the PUCO extends recovery beyond twelve months and/or does not commence cost recovery by April 2013, OPCo requested approval of a weighted average cost of capital carrying charge, effective April 2013. As of December 31, 2012, OPCo recorded $62 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it would reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

The PUCO selected an outside consultant to conduct an audit of OPCo's FAC for 2009. The outside consultant provided its audit report to the PUCO. In January 2012, the PUCO ordered that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. OPCo recorded a $30 million net favorable adjustment on the statement of income in the second quarter of 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, intervenors filed with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes. As of December 31, 2012, the amount of OPCo's carrying costs that could potentially be reduced due to the accumulated income tax issue is estimated to be approximately $36 million, including $19 million of unrecognized equity carrying costs. These amounts include the carrying costs exposure of the 2009 FAC audit, which has been appealed by an intervenor to the Supreme Court of Ohio. Decisions from the PUCO are pending. Management is unable to predict the outcome of these proceedings. If the PUCO orders result in a reduction to the FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filing and the FAC aspect of the ESP order was upheld by the Supreme Court of Ohio. The approval of the FAC as part of the ESP, together with the PUCO approval of the interim arrangement, provided the basis to record a regulatory asset for the difference between the approved market price and the rate paid by Ormet. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. In November 2009, OPCo requested that the PUCO approve recovery of the deferral under the interim agreement plus a weighted average cost of capital carrying charge. The deferral amount is included in OPCo's FAC phase-in deferral balance. In the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related regulatory asset and requested that the PUCO prevent OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request. The intervenors raised the issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement. This issue remains pending before the PUCO. If OPCo is not ultimately permitted to fully recover its requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Special Rate Mechanism for Ormet

In October 2012, the PUCO issued an order approving a delayed payment plan for Ormet of its October and November 2012 power billings totaling $27 million to be paid in equal monthly installment over the period January 2014 to May 2015 without interest. In the event Ormet does not pay the $27 million, the PUCO permitted OPCo to recover the unpaid balance, up to $20 million, in the economic development rider. To the extent unpaid amounts exceed $20 million, it will reduce future net income and cash flows.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2012, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting all collected pre-construction costs be refunded to Ohio ratepayers with interest.

Management cannot predict the outcome of these proceedings concerning the Ohio IGCC plant or what effect, if any, these proceedings would have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the completed facility. As of December 31, 2012, excluding costs attributable to its joint owners and a $62 million provision for a Texas capital costs cap, SWEPCo has capitalized approximately $1.7 billion of expenditures, including AFUDC and capitalized interest of $328 million and related transmission costs of $120 million.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to the Arkansas Supreme Court's decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This portion of the Turk Plant output is currently not subject to cost-based rate recovery and is being sold into the SPP market.

The PUCT approved a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers (TIEC) filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant should be revoked because the Turk Plant is unnecessary to serve retail customers. The Texas District Court and the Texas Court of Appeals affirmed the PUCT's order in all respects. In April 2012, SWEPCo and TIEC filed petitions for review at the Supreme Court of Texas. The Supreme Court of Texas has requested full briefing from the parties.

If SWEPCo cannot recover all of its investment and expenses related to the Turk Plant, it would reduce future net income and cash flows and impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant Unit 2 from 2040 to 2016, (b) proposed increased vegetation management expenditures and (c) included a return on and of the Stall Unit as of December 2011 and associated operations and maintenance costs.

In September 2012, an Administrative Law Judge issued an order that granted the establishment of SWEPCo's existing rates as temporary rates beginning in late January 2013, subject to true-up to the final PUCT-approved rates.

In December 2012, several intervenors, including the PUCT staff, filed testimony that recommended an annual base rate increase between $16 million and $51 million based upon a return on common equity between 9.0% and 9.55%. In addition, two intervenors recommended that the Turk Plant be excluded from rate base. A decision from the PUCT is expected in the second quarter of 2013. If the PUCT does not approve full cost recovery of SWEPCo's assets, it would reduce future net income and cash flows and impact financial condition.

Louisiana 2012 Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and a hearing was conducted. The settlement provided that SWEPCo would increase Louisiana total rates by approximately $2 million annually, effective March 2013, consisting of an increase in base rates of approximately $85 million annually offset by a decrease in fuel rates of approximately $83 million annually. The proposed March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and prudence review of the Turk Plant to be initiated by SWEPCo no later than May 2013. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover all non-fuel Turk Plant costs and a full weighted-average cost of capital return on the Turk Plant portion of rate base beginning January 2013. A decision from the LPSC is expected in the first quarter of 2013.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. As of December 31, 2012, SWEPCo has incurred $11 million related to this project, including AFUDC and company overheads. The APSC staff and the Sierra Club filed testimony that recommended the APSC deny the requested declaratory order. A hearing is scheduled for March 2013. If SWEPCo is not ultimately permitted to recover its incurred costs, it would reduce future net income and cash flows.

APCo and WPCo Rate Matters

Plant Transfers

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, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant, Unit 3 and a one-half interest in the Mitchell Plant, comprising 1,647 MW of average annual generating capacity presently owned by OPCo. Hearings at the Virginia SCC and the WVPSC are scheduled for April 2013 and July 2013, respectively. If the transfers are approved, APCo and WPCo anticipate seeking cost recovery when they file their next base rate cases.

Virginia Fuel Filing

In April 2012, APCo filed an application with the Virginia SCC for an annual increase in fuel revenues of $117 million to be effective June 2012. The filing included forecasted costs for the 15-month period ended August 2013 and requested recovery of APCo's anticipated unrecovered fuel balance as of May 2012 over a two-year period commencing in June 2012. The non-incremental portion of APCo's forecasted and deferred wind purchased power costs were reflected in APCo's filing. In June 2012, the Virginia SCC approved the application as filed.

Environmental Rate Adjustment Clause (Environmental RAC)

In November 2011, the Virginia SCC issued an order which approved APCo's Environmental RAC recovery of $30 million to be collected over one year beginning in February 2012 but denied recovery of certain environmental costs. As a result, in 2011, APCo recorded a pretax write-off of $31 million on the statement of income related to environmental compliance costs incurred from January 2009 through December 2010. APCo appealed the Virginia SCC decision to the Supreme Court of Virginia. In November 2012, the Supreme Court of Virginia issued an order which allowed APCo to recover an additional $6 million of 2009 and 2010 actual Environmental RAC costs and affirmed the portion of the November 2011 order that denied recovery of certain environmental costs. The Virginia SCC issued an order in December 2012 which permitted APCo to extend the current Environmental RAC surcharge for the months of February and March 2013 in order to collect the $6 million.

Generation Rate Adjustment Clause (Generation RAC)

In January 2012, the Virginia SCC issued a Generation RAC order which allowed APCo to recover $26 million annually, effective March 2012, related to recovery of the Dresden Plant. APCo filed with the Virginia SCC to continue the current Generation RAC rate to recover costs of the Dresden Plant through February 2014. In December 2012, the Virginia SCC granted APCo's application as filed and required APCo to submit a new Generation RAC filing in March 2013.

APCo IGCC Plant

As of December 31, 2012, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $9 million applicable to its Virginia jurisdiction. If the costs are not recoverable, it would reduce future net income and cash flows and impact financial condition.

APCo's and WPCo's Expanded Net Energy Charge (ENEC) Filing

In March 2012, West Virginia passed securitization legislation, which allows the WVPSC to establish a regulatory framework to securitize certain deferred ENEC balances and other ENEC related assets. Also in March 2012, APCo and WPCo filed their ENEC application with the WVPSC for the fourth year of a four-year phase-in plan which requested no change in ENEC rates if the WVPSC issues a financing order allowing securitization of the under-recovered ENEC deferral and other ENEC-related assets. If the financing order is not issued, APCo and WPCo requested that recovery of these costs be allowed in current rates.

In July 2012, the WVPSC issued an order that approved a settlement agreement which recommended no change in total ENEC rates but reflected a $24 million increase in the construction surcharge and a $24 million decrease in ENEC rates. In August 2012, APCo and WPCo filed with the WVPSC a request for a financing order to securitize a total of $422 million related to the December 2011 under-recovered ENEC deferral balance including other ENEC-related assets of $13 million and related future financing costs of $7 million. Upon completion of the securitization, APCo would offset its current ENEC rates by an amount to recover the securitized balance over the securitization period. In January 2013, intervenors filed testimony that recommended securitization of approximately $370 million. The differences between APCo's and WPCo's request and the intervenors' testimony represent previously approved ENEC-related deferred amounts being recovered in the ENEC over extended periods, various amounts deferred subsequent to the 2011 securitization period and related future securitization financing costs. As of December 31, 2012, APCo's ENEC under-recovery balance of $299 million, net of 2012 over-recovery, was recorded in Regulatory Assets on the balance sheet, excluding $4 million of unrecognized equity carrying costs and $12 million of other ENEC-related assets. APCo and WPCo are currently in settlement discussions with intervenors.

PSO Rate Matters

PSO 2008 Fuel and Purchased Power

In 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In October 2012, the OCC issued a final order that found PSO's fuel and purchased power costs were prudently incurred without any disallowance and that PSO's shareholder's portion of off-system sales margins would remain at 25%.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES) Unit 4 in 2016 and additional environmental controls on NES Unit 3 to continue operations through 2026. The plan requested approval for (a) cost recovery through base rates by 2026 of an estimated $256 million of new environmental investment that will be incurred prior to 2016 at NES Unit 3, (b) cost recovery through 2026 of NES Units 3 and 4 net book value (combined net book value of the two units is $234 million as of December 31, 2012), (c) cost recovery through base rates of an estimated $83 million of new investment incurred through 2016 at various gas units and (d) a new 15-year purchase power agreement (PPA) with a nonaffiliated entity, effective in 2016, with cost recovery through a rider, including an annual earnings component of $3 million. Although the environmental compliance plan does not seek to put any new costs into rates at this time, PSO anticipates seeking cost recovery when filing its next base rate case, which is expected to occur no later than 2014.

In January 2013, testimony filed by the OCC staff and the Oklahoma Office of the Attorney General generally agreed with PSO's plan, although they recommended no earnings component on the PPA and to delay final decisions on parts of the plan including cost recovery of NES Unit 3 and any increases in fuel costs due to reductions in the output of energy from NES Unit 3 beginning in 2021. The testimony recommended that cost recovery could extend past 2026 on parts of the plan and recommended a $175 million cost cap on NES Unit 3 environmental investment.

Also, an intervenor representing some of PSO's large industrial users opposed virtually all of PSO's plan, including recommending no cost recovery of NES Units 3 and 4 book value amounts not recovered at the time of their retirement and no recovery of the PPA costs, including earnings on the PPA. A hearing is scheduled for April 2013.

I&M Rate Matters

2011 Indiana Base Rate Case

In September 2011, I&M filed a request with the IURC for a net annual increase in Indiana base rates of $149 million based upon a return on common equity of 11.15%. The $149 million net annual increase reflects an increase in base rates of $178 million offset by proposed corresponding reductions of $13 million to the off-system sales sharing rider, $9 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The request included an increase in depreciation rates that would result in an increase of approximately $25 million in annual depreciation expense. Included in the depreciation rates increase was a decrease in the average remaining life of Tanners Creek Plant to account for the change in the retirement date of Tanners Creek Plant, Units 1-3 from 2020 to 2014. In May 2012, I&M filed rebuttal testimony which changed the retirement date for Tanners Creek Plant, Units 1-3 to 2015 and supported an increase of $170 million in base rates, excluding reductions to certain riders.

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%, effective March 2013. The $85 million annual increase in base rates will be offset by corresponding reductions of $5 million to the off-system sales sharing rider, $11 million to the PJM cost rider and $7 million to the clean coal technology rider rates. The IURC granted the requested increase in depreciation rates, modified the shareholder's portion of off-system sales margins to 50% below and above the $27 million imbedded in base rates, established a capacity tracker and established a major storm damage restoration reserve.

Cook Plant Life Cycle Management Project

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the Cook Plant Life Cycle Management Project (LCM Project), which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life. The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC.

In Indiana, I&M requested recovery of certain project costs, including interest, through a new rider effective January 2013. In Michigan, I&M requested that the MPSC approve a Certificate of Need and authorize I&M to defer, on an interim basis, incremental depreciation and related property tax costs, including interest, along with study, analysis and development costs until the applicable LCM costs are included in I&M's base rates. As of December 31, 2012, I&M has incurred $176 million related to the LCM Project, including AFUDC.

In August 2012, intervenors filed testimony in Indiana. The Indiana Michigan Power Company Industrial Group recommended that I&M recover $229 million in a rider with the remaining costs to be requested in future base rate cases. The Indiana Office of Utility Consumer Counselor (OUCC) recommended a maximum of $408 million of LCM project costs be recovered in a rider, and a maximum of $299 million for projects the OUCC believes are not related to LCM to be recovered in future base rates. The IURC held a hearing in January 2013.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project with total costs of $851 million (Michigan jurisdictional share is approximately 15%) for the period 2013 through 2018. The order provided that depreciation, property taxes and a return using the overall rate of return approved in I&M's last Michigan base rate case related to the 2013 through 2018 LCM Project costs can be deferred until these costs are included in rates. The order excluded from the CON $176 million of LCM costs spent prior to 2013 as $39 million was included in the determination of Michigan base rates, effective April 2012, and the remaining $137 million in CWIP will be requested in a future base rate case. The order also excluded $142 million of future LCM costs, which if incurred, will be requested in a future base rate case. Under Michigan law, the approved CON amount is eligible for a cost increase allowance of 10%, up to $85 million, of the approved project costs in the event project costs exceed the approved level of costs.

If I&M is not ultimately permitted to recover its LCM Project costs, it would reduce future net income and cash flows and impact financial condition.

Rockport Plant Environmental Controls

I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit one unit at its Rockport Plant with environmental controls estimated to cost $1.4 billion to comply with new requirements. AEGCo and I&M jointly own Unit 1 and jointly lease Unit 2 of the Rockport Plant. I&M is also evaluating options related to the maturity of the lease for Rockport Plant Unit 2 in 2022 and continues to investigate alternative compliance technologies for these units as part of its overall compliance strategy. As of December 31, 2012, we have incurred $71 million related to these environmental controls, including AFUDC. If we are not ultimately permitted to recover our incurred costs, it would reduce future net income and cash flows.

In February 2013, I&M filed a motion with the IURC to dismiss its request for approval of a CPCN for environmental controls after modification to the NSR consent decree. Under the terms of the NSR consent decree modification, the units of Rockport Plant will be equipped with dry sorbent injection systems in 2015 and have options to retrofit additional SO_2 controls, refuel, repower or retire in 2025 and 2028.

KPCo Rate Matters

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.

FERC Rate Matters

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. 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 filings requested approval to transfer at net book value approximately 9,200 MW of OPCo-owned generation assets to a new wholly-owned company, AEPGenCo. The AEP East Companies also requested FERC approval to transfer at net book value OPCo's current two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and 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 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, the Virginia SCC and the WVPSC. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters.

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4. EFFECTS OF REGULATION

Regulatory assets are comprised of the following items:

	December 31, 2012	2011	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 86	$ 56	1 year
Under-recovered Fuel Costs - does not earn a return	2	9	1 year
Total Current Regulatory Assets	$ 88	$ 65	
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Storm Related Costs	$ 23	$ 24	
Economic Development Rider	13	13	
Other Regulatory Assets Not Yet Being Recovered	1	-	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	172	10	
Virginia Environmental Rate Adjustment Clause	29	18	
Mountaineer Carbon Capture and Storage Product Validation Facility	14	14	
Litigation Settlement	11	11	
Deferred Wind Power Costs	5	38	
Special Rate Mechanism for Century Aluminum	-	13	
Other Regulatory Assets Not Yet Being Recovered	36	14	
Total Regulatory Assets Not Yet Being Recovered	304	155	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Ohio Fuel Adjustment Clause	519	521	6 years
West Virginia Expanded Net Energy Charge	273	327	(a)
Ohio Deferred Asset Recovery Rider	152	173	6 years
Unamortized Loss on Reacquired Debt	82	92	31 years
Ohio Capacity Deferral	66	-	6 years
Transmission Cost Recovery Rider	49	28	3 years
Meter Replacement Costs	47	39	10 years
Storm Related Costs	36	65	6 years
RTO Formation/Integration Costs	15	18	7 years
Red Rock Generating Facility	10	10	44 years
Economic Development Rider	5	12	1 year
Capacity Auction True-Up	-	692	
Other Regulatory Assets Being Recovered	10	15	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	1,896	2,308	12 years
Income Taxes, Net	1,353	1,237	44 years
Postemployment Benefits	45	47	5 years
Virginia Transmission Rate Adjustment Clause	33	20	2 years
Cook Nuclear Plant Refueling Outage Levelization	27	41	3 years
Storm Related Costs	27	35	6 years
West Virginia Expanded Net Energy Charge	26	32	(a)
Distribution Decoupling	16	-	2 years
Deferred Restructuring Costs	15	18	6 years
Deferred PJM Fees	14	22	2 years
Vegetation Management	13	11	1 year
Peak Demand Reduction/Energy Efficiency	12	8	1 year
Asset Retirement Obligation	9	14	8 years
Virginia Environmental Rate Adjustment Clause	8	24	1 year
Unrealized Loss on Forward Commitments	8	16	2 years
Restructuring Transition Costs	5	8	4 years
Other Regulatory Assets Being Recovered	31	38	various
Total Regulatory Assets Being Recovered	4,802	5,871	
Total Noncurrent Regulatory Assets	$ 5,106	$ 6,026	

(a) Request for securitization is pending from the WVPSC to recover $422 million as securitized transition assets from ratepayers over the securitization bond period.

Regulatory liabilities are comprised of the following items:

	December 31, 2012	December 31, 2011	Remaining Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 25	$ 5	1 year
Over-recovered Fuel Costs - does not pay a return	22	3	1 year
Total Current Regulatory Liabilities	$ 47	$ 8	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Louisiana Refundable Construction Financing Costs	$ 96	$ 53	
Other Regulatory Liabilities Not Yet Being Paid	4	5	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	9	8	
Total Regulatory Liabilities Not Yet Being Paid	109	66	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,511	2,270	(a)
Advanced Metering Infrastructure Surcharge	83	78	8 years
Deferred Investment Tax Credits	23	27	48 years
Excess Earnings	12	13	41 years
Other Regulatory Liabilities Being Paid	1	4	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	436	377	(b)
Deferred Investment Tax Credits	136	144	50 years
Over-recovery of Transition Charges	57	41	15 years
Unrealized Gain on Forward Commitments	46	41	5 years
Spent Nuclear Fuel Liability	43	43	(b)
Peak Demand Reduction/Energy Efficiency	31	40	2 years
Deferred State Income Tax Coal Credits	29	29	10 years
Other Regulatory Liabilities Being Paid	27	22	various
Total Regulatory Liabilities Being Paid	3,435	3,129	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,544	$ 3,195	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us 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 our financial statements.

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. We forecast approximately $3.6 billion of construction expenditures, excluding equity AFUDC and capitalized interest, for 2013. The subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes our 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 millions)		
Fuel Purchase Contracts (a)	$ 2,642	$ 3,928	$ 2,854	$ 2,908	$ 12,332
Energy and Capacity Purchase Contracts (b)	177	359	368	2,494	3,398
Construction Contracts for Capital Assets (c)	187	-	-	-	187
Total	$ 3,006	$ 4,287	$ 3,222	$ 5,402	$ 15,917

(a) Represents contractual commitments to purchase coal, natural gas, uranium 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 we have 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

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

Letters of Credit

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two credit facilities totaling $3.25 billion, under which we may issue up to $1.35 billion as letters of credit. As of December 31, 2012, the maximum future payments for letters of credit issued under the credit facilities were $131 million with maturities ranging from January 2013 to April 2014. In February 2013, we increased and extended the $1.5 billion credit facility due in June 2015 to $1.75 billion due in June 2016, extended the $1.75 billion credit facility due in July 2016 to July 2017 and issued a $1 billion interim credit facility due in May 2015 to fund certain OPCo maturities.

We have $402 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $407 million. The letters of credit have maturities ranging from March 2013 to July 2014. In February 2013, we extended certain bilateral letters of credit due in March 2013 to July 2014 and March 2015.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of December 31, 2012, SWEPCo has collected approximately $59 million through a rider for final mine closure and reclamation costs, of which $18 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $41 million is recorded in Asset Retirement Obligations on the balance sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several 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, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the "Dispositions" section of Note 6. As of December 31, 2012, there were no material liabilities recorded for any indemnifications.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 12 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

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. We will continue to defend against the claims. We are 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. We believe the action is without merit and will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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, sludge, low-level radioactive waste and SNF. 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, our generating plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur 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, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites for which alleged liability is unresolved. There are eight additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at three sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our 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.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's reserve is approximately $10 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our 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 as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M site discussed above.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $14 million, $14 million and $14 million for the years ended December 31, 2012, 2011 and 2010, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2012 and 2011, the total decommissioning trust fund balance was $1.4 billion and $1.3 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. As of December 31, 2012 and 2011, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $308 million and $308 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the Federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $20 million and $14 million in 2012 and 2011, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2013. The proceeds reduced costs for dry cask storage. As of December 31, 2012, I&M has deferred $32 million in Prepayments and Other Current Assets and $13 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 10 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $40 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

Cook Plant, Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant, Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The installation of the new turbine rotors and other equipment occurred as planned during the fall 2011 refueling outage of Unit 1.

I&M maintains insurance through NEIL. In February 2013, we signed an agreement and received payment from NEIL to settle the remaining insurance claims. The settlement did not have a material impact on net income, cash flows or financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear 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. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See "Nuclear Contingencies" section of this footnote for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. 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.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the dismissal of several cases involving AEP companies in Nevada to the Ninth Circuit Court of Appeals. Oral argument was held in October 2012. We will continue to defend the cases on appeal. We believe the provision we have is adequate. We believe the remaining exposure is immaterial.

6. ACQUISITIONS, DISPOSITIONS AND IMPAIRMENTS

ACQUISITIONS

2012

BlueStar Energy (Generation and Marketing segment)

In March 2012, we completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for $70 million. This transaction also included goodwill of $15 million, intangible assets associated with sales contracts and customer accounts of $58 million and liabilities associated with supply contracts of $25 million. BlueStar has been in operation since 2002. Beginning in June 2012, BlueStar began doing business as AEP Energy. AEP Energy provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions throughout the United States, including demand response and energy efficiency services.

2010

Valley Electric Membership Corporation (Utility Operations segment)

In October 2010, SWEPCo purchased certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO) for approximately $102 million and began serving VEMCO's 30,000 customers in Louisiana.

Other Matters

Enron Bankruptcy

In February 2011, we reached a $425 million settlement covering all claims with BOA and Enron related to our purchase of Houston Pipeline Company (HPL) from Enron in 2001. As part of the settlement, we received title to the 55 billion cubic feet of natural gas in the Bammel storage facility and recorded this asset at fair value. Under the HPL sales agreement, we have a service obligation to the buyer for the right to use the cushion gas through May 2031. We recognized the obligation as a liability and will amortize it over the life of the agreement.

The settlement resulted in a pretax gain of $51 million and a net loss after tax of $22 million primarily due to an unrealized capital loss valuation allowance of $56 million.

DISPOSITIONS

2010

Texas Transmission Facilities (Utility Operations segment)

In 2010, TCC and TNC sold $66 million and $73 million, respectively, of transmission facilities to ETT. There were no gains or losses recorded on these sale transactions.

Intercontinental Exchange, Inc. (ICE) (All Other)

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain. We recorded the gain in Interest and Investment Income on the statement of income for the year ended December 31, 2010.

IMPAIRMENTS

2012

Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 (Utility Operations segment)

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, we performed an evaluation of the recoverability of generation assets. As a result, in November 2012, we, using generating unit specific estimated future cash flows, concluded that OPCo had a material impairment of certain generation assets. Under a market-based value approach, using level 3 unobservable inputs, we determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, OPCo recorded a pretax impairment of $287 million in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant Unit 6, Conesville Plant Unit 3, Kammer Plant Units 1-3, Muskingum River Plant Units 1-4, Sporn Plant Units 2 and 4 and Picway Plant Unit 5 generating units which includes $13 million of related material and supplies inventory.

Turk Plant (Utility Operations segment)

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the statement of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

2011

Turk Plant (Utility Operations segment)

In the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Muskingum River Plant Unit 5 FGD Project (MR5) (Utility Operations segment)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, we determined that OPCo was not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statement of income.

Sporn Plant Unit 5 (Utility Operations segment)

In the third quarter of 2011, we decided to no longer offer the output of Sporn Unit 5 into the PJM market. Sporn Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Unit 5 from the Interconnection Agreement. As a result, in the third quarter of 2011, OPCo recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statement of income.

7. BENEFIT PLANS

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

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide health and life insurance benefits for retired employees.

We recognize the funded status associated with our defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, 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. We record a regulatory asset instead of other comprehensive income for qualifying benefit costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31 of each year used in the measurement of our 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	4.95 % (a)	4.85 % (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.

We use a duration-based method to determine the discount rate for our 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 4.95%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2012	2011	2010	2012	2011	2010
Discount Rate	4.55 %	5.05 %	5.60 %	4.75 %	5.25 %	5.85 %
Expected Return on Plan Assets	7.25 %	7.75 %	8.00 %	7.25 %	7.50 %	8.00 %
Rate of Compensation Increase	4.85 %	4.85 %	4.60 %	NA	NA	NA

NA Not applicable.

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

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

Health Care Trend Rates	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 millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 24	$ (19)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	118	(89)

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. We monitor the plans to control security diversification and ensure compliance with our 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.

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 millions)			
Benefit Obligation as of January 1	$ 4,991	$ 4,807	$ 2,227	$ 2,125
Service Cost	76	72	47	42
Interest Cost	223	237	103	109
Actuarial Loss	299	169	148	253
Plan Amendment Prior Service Credit	-	-	(570)	(196)
Curtailment and Settlements	(1)	-	-	1
Benefit Payments	(383)	(294)	(151)	(150)
Participant Contributions	-	-	35	34
Medicare Subsidy	-	-	10	9
Benefit Obligation as of December 31	$ 5,205	$ 4,991	$ 1,849	$ 2,227
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1	$ 4,303	$ 3,858	$ 1,410	$ 1,461
Actual Gain (Loss) on Plan Assets	560	282	178	(14)
Company Contributions	216	457	96	79
Participant Contributions	-	-	35	34
Benefit Payments	(383)	(294)	(151)	(150)
Fair Value of Plan Assets as of December 31	$ 4,696	$ 4,303	$ 1,568	$ 1,410
Underfunded Status as of December 31	$ (509)	$ (688)	$ (281)	$ (817)

Benefit 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 millions)			
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (7)	$ (8)	$ (4)	$ (4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(502)	(680)	(277)	(813)
Underfunded Status	$ (509)	$ (688)	$ (281)	$ (817)

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

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2012	2011	2012	2011
Components	(in millions)			
Net Actuarial Loss	$ 2,111	$ 2,208	$ 989	$ 979
Prior Service Cost (Credit)	11	10	(762)	(210)
Transition Obligation	-	-	-	1
Recorded as				
Regulatory Assets	$ 1,774	$ 1,818	$ 108	$ 479
Deferred Income Taxes	122	140	42	102
Net of Tax AOCI	226	260	77	189

Components of the change in amounts included in AOCI and 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 millions)			
Actuarial Loss During the Year	$ 58	$ 201	$ 67	$ 370
Prior Service Credit	-	-	(570)	(191)
Amortization of Actuarial Loss	(155)	(122)	(57)	(29)
Amortization of Prior Service Credit (Cost)	1	(1)	18	1
Amortization of Transition Obligation	-	-	(1)	(2)
Change for the Year	$ (96)	$ 78	$ (543)	$ 149

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 millions)			
Equities:						
Domestic	$ 1,308	$ -	$ -	$ -	$ 1,308	27.9 %
International	497	-	-	-	497	10.5 %
Real Estate Investment Trusts	91	-	-	-	91	1.9 %
Common Collective Trust - International	-	4	-	-	4	0.1 %
Subtotal - Equities	1,896	4	-	-	1,900	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	32	-	-	32	0.7 %
United States Government and Agency Securities	-	715	-	-	715	15.2 %
Corporate Debt	-	1,235	-	-	1,235	26.3 %
Foreign Debt	-	199	-	-	199	4.2 %
State and Local Government	-	44	-	-	44	0.9 %
Other - Asset Backed	-	36	-	-	36	0.8 %
Subtotal - Fixed Income	-	2,261	-	-	2,261	48.1 %
Real Estate	-	-	220	-	220	4.7 %
Alternative Investments	-	-	195	-	195	4.2 %
Securities Lending	-	80	-	-	80	1.7 %
Securities Lending Collateral (a)	-	-	-	(91)	(91)	(1.9)%
Cash and Cash Equivalents	-	126	-	-	126	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	5	5	0.1 %
Total	$ 1,896	$ 2,471	$ 415	$ (86)	$ 4,696	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 millions)		
Balance as of January 1, 2012	$ 6	$ 163	$ 161	$ 330
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	30	10	40
Relating to Assets Sold During the Period	(2)	-	4	2
Purchases and Sales	(4)	27	20	43
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 220	$ 195	$ 415

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 millions)			
Equities:						
Domestic	$ 422	$ -	$ -	$ -	$ 422	26.9 %
International	505	-	-	-	505	32.2 %
Subtotal - Equities	927	-	-	-	927	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	72	-	-	72	4.6 %
United States Government and Agency Securities	-	82	-	-	82	5.2 %
Corporate Debt	-	155	-	-	155	9.9 %
Foreign Debt	-	26	-	-	26	1.7 %
State and Local Government	-	7	-	-	7	0.5 %
Other - Asset Backed	-	10	-	-	10	0.6 %
Subtotal - Fixed Income	-	352	-	-	352	22.5 %
Trust Owned Life Insurance:						
International Equities	-	52	-	-	52	3.3 %
United States Bonds	-	163	-	-	163	10.3 %
Cash and Cash Equivalents	62	11	-	-	73	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	1	1	0.1 %
Total	$ 989	$ 578	$ -	$ 1	$ 1,568	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 millions)			
Equities:						
Domestic	$ 1,455	$ -	$ -	$ -	$ 1,455	33.8 %
International	399	-	-	-	399	9.3 %
Real Estate Investment Trusts	104	-	-	-	104	2.4 %
Common Collective Trust - International	-	128	-	-	128	3.0 %
Subtotal - Equities	1,958	128	-	-	2,086	48.5 %
Fixed Income:						
Common Collective Trust - Debt	-	26	-	-	26	0.6 %
United States Government and Agency Securities	-	566	-	-	566	13.2 %
Corporate Debt	-	985	6	-	991	23.0 %
Foreign Debt	-	190	-	-	190	4.4 %
State and Local Government	-	48	-	-	48	1.1 %
Other - Asset Backed	-	26	-	-	26	0.6 %
Subtotal - Fixed Income	-	1,841	6	-	1,847	42.9 %
Real Estate	-	-	163	-	163	3.8 %
Alternative Investments	-	-	161	-	161	3.7 %
Securities Lending	-	215	-	-	215	5.0 %
Securities Lending Collateral (a)	-	-	-	(236)	(236)	(5.5)%
Cash and Cash Equivalents	-	93	-	-	93	2.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	(26)	(26)	(0.6)%
Total	$ 1,958	$ 2,277	$ 330	$ (262)	$ 4,303	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 millions)		
Balance as of January 1, 2011	$ -	$ 83	$ 130	$ 213
Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	22	9	31
Relating to Assets Sold During the Period	-	-	3	3
Purchases and Sales	-	58	19	77
Transfers into Level 3	6	-	-	6
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2011	$ 6	$ 163	$ 161	$ 330

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 millions)			
Equities:						
Domestic	$ 348	$ -	$ -	$ -	$ 348	24.7 %
International	380	-	-	-	380	27.0 %
Common Collective Trust - Global	-	99	-	-	99	7.0 %
Subtotal - Equities	728	99	-	-	827	58.7 %
Fixed Income:						
Common Collective Trust - Debt	-	69	-	-	69	4.9 %
United States Government and Agency Securities	-	81	-	-	81	5.7 %
Corporate Debt	-	152	-	-	152	10.8 %
Foreign Debt	-	32	-	-	32	2.3 %
State and Local Government	-	9	-	-	9	0.6 %
Other - Asset Backed	-	2	-	-	2	0.1 %
Subtotal - Fixed Income	-	345	-	-	345	24.4 %
Trust Owned Life Insurance:						
International Equities	-	46	-	-	46	3.3 %
United States Bonds	-	158	-	-	158	11.2 %
Cash and Cash Equivalents	17	23	-	-	40	2.9 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	(6)	(6)	(0.5)%
Total	$ 745	$ 671	$ -	$ (6)	$ 1,410	100.0 %

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

Determination of Pension Expense

We base our determination of pension expense or income 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 millions)	
Qualified Pension Plan	$ 5,001	$ 4,808
Nonqualified Pension Plans	82	89
Total	$ 5,083	$ 4,897

For our 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 December 31, 2012	2011
	(in millions)	
Projected Benefit Obligation	$ 5,205	$ 4,991
Accumulated Benefit Obligation	$ 5,083	$ 4,897
Fair Value of Plan Assets	4,696	4,303
Underfunded Accumulated Benefit Obligation	$ (387)	$ (594)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $108 million and the OPEB plans of $4 million during 2013. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, we may also make additional discretionary contributions to maintain the funded status of the plan. For the OPEB plans, expected payments include the payment of unfunded benefits.

The table below reflects the total benefits expected to be paid from the plan or from our assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical coverage will be capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. In December 2011, we amended the prescription drug program 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:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2013	$ 340	$ 140	$ -
2014	349	146	-
2015	356	153	-
2016	359	162	-
2017	364	171	-
Years 2018 to 2022, in Total	1,844	990	2

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost for the plans for the years ended December 31, 2012, 2011 and 2010:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2012	2011	2010	2012	2011	2010
	(in millions)					
Service Cost	$ 76	$ 72	$ 111	$ 47	$ 42	$ 47
Interest Cost	223	237	253	103	109	113
Expected Return on Plan Assets	(319)	(314)	(312)	(101)	(109)	(105)
Curtailment	-	-	-	-	1	-
Amortization of Transition Obligation	-	-	-	1	2	27
Amortization of Prior Service Cost (Credit)	(1)	1	-	(18)	(1)	-
Amortization of Net Actuarial Loss	155	122	89	57	29	29
Net Periodic Benefit Cost	134	118	141	89	73	111
Capitalized Portion	(42)	(37)	(44)	(28)	(22)	(35)
Net Periodic Benefit Cost Recognized as Expense	$ 92	$ 81	$ 97	$ 61	$ 51	$ 76

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 millions)	
Net Actuarial Loss	$ 176	$ 64
Prior Service Cost (Credit)	3	(69)
Total Estimated 2013 Amortization	$ 179	$ (5)
Expected to be Recorded as		
Regulatory Asset	$ 148	$ (7)
Deferred Income Taxes	11	1
Net of Tax AOCI	20	1
Total	$ 179	$ (5)

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. 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 $66 million in 2012, $64 million in 2011 and $61 million in 2010.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by us and benefits are paid from our general assets.

The UMWA pension benefits are administered through a multiemployer plan that is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. Required contributions not made by any employer may result in other employers bearing the unfunded plan obligations, while a withdrawing employer may be subject to a withdrawal liability. UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-1050282, Plan Number 002), which under the Pension Protection Act of 2006 (PPA) was in Seriously Endangered Status for the plan years ending June 30, 2012 and 2011, without utilization of extended amortization provisions. The Plan adopted a funding improvement plan in May 2012, as required under the PPA. Contributions in 2012, 2011 and 2010 were made under a collective bargaining agreement that is scheduled to expire December 31, 2013. We contributed immaterial amounts in 2012, 2011 and 2010 that represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2012, 2011 and 2010. The contributions we made did not include a surcharge. There are no minimum contributions for future years.

8. BUSINESS SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are outlined below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries and transmission joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

AEP River Operations

- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Nonregulated generation in ERCOT.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

The remainder of our activities is presented as All Other. While not considered a reportable segment, All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations, which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

The tables below present our reportable segment information for the years ended December 31, 2012, 2011 and 2010 and balance sheet information as of December 31, 2012 and 2011. These amounts include certain estimates and allocations where necessary.

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)				
Year Ended December 31, 2012							
Revenues from:							
External Customers	$ 13,670	$ 7	$ 647	$ 599	$ 22	$ -	$ 14,945
Other Operating Segments	108	17	20	1	8	(154)	-
Total Revenues	$ 13,778	$ 24	$ 667	$ 600	$ 30	$ (154)	$ 14,945
Asset Impairments and Other Related Charges	$ 300	$ -	$ -	$ -	$ -	$ -	$ 300
Depreciation and Amortization	1,734	3	29	28	-	(12)(b)	1,782
Interest Income	7	-	-	-	20	(19)	8
Carrying Costs Income	53	-	-	-	-	-	53
Interest Expense	882	3	17	19	102	(35)(b)	988
Income Tax Expense	560	17	7	3	17	-	604
Net Income (Loss)	1,299	43	15	7	(102)	-	1,262
Gross Property Additions	2,625	392	31	71	-	-	3,119

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)				
Year Ended December 31, 2011							
Revenues from:							
External Customers	$ 14,088	$ 3	$ 696	$ 305	$ 24	$ -	$ 15,116
Other Operating Segments	112	5	20	1	8	(146)	-
Total Revenues	$ 14,200	$ 8	$ 716	$ 306	$ 32	$ (146)	$ 15,116
Asset Impairments and Other Related Charges	$ 139	$ -	$ -	$ -	$ -	$ -	$ 139
Depreciation and Amortization	1,613	-	28	25	2	(13)(b)	1,655
Interest Income	29	-	-	(1)	17	(18)	27
Carrying Costs Income	393	-	-	-	-	-	393
Interest Expense	886	1	18	18	43	(33)(b)	933
Income Tax Expense (Credit)	722	2	24	(18)	88	-	818
Income (Loss) Before Extraordinary Item	$ 1,549	$ 30	$ 45	$ 14	$ (62)	$ -	$ 1,576
Extraordinary Item, Net of Tax	373	-	-	-	-	-	373
Net Income (Loss)	$ 1,922	$ 30	$ 45	$ 14	$ (62)	$ -	$ 1,949
Gross Property Additions	$ 2,405	$ 263	$ 18	$ 2	$ 214	$ -	$ 2,902

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
				(in millions)			
Year Ended December 31, 2010							
Revenues from:							
External Customers	$ 13,687	$ -	$ 566	$ 173	$ 1	$ -	$ 14,427
Other Operating Segments	105	1	22	-	14	(142)	-
Total Revenues	$ 13,792	$ 1	$ 588	$ 173	$ 15	$ (142)	$ 14,427
Asset Impairments and Other Related Charges	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Depreciation and Amortization	1,598	-	24	30	2	(13)(b)	1,641
Interest Income	8	-	-	2	31	(20)	21
Carrying Costs Income	70	-	-	-	-	-	70
Interest Expense	942	-	14	20	58	(35)(b)	999
Income Tax Expense (Credit)	651	(1)	19	(20)	(6)	-	643
Net Income (Loss)	1,192	9	37	25	(45)	-	1,218
Gross Property Additions	2,440	35	23	1	1	-	2,500

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2012							
Total Property, Plant and Equipment	$ 55,707	$ 748	$ 636	$ 621	$ 8	$ (266)	$ 57,454
Accumulated Depreciation and Amortization	18,344	4	161	246	7	(71)	18,691
Total Property, Plant and Equipment - Net	$ 37,363	$ 744	$ 475	$ 375	$ 1	$ (195)	$ 38,763
Total Assets	$ 51,477	$ 1,216	$ 670	$ 1,005	$ 17,191	$ (17,192) (c)	$ 54,367
Investments in Equity Method Investees	24	393	43	-	5	-	465

	Utility Operations	Transmission Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
				(in millions)			
December 31, 2011							
Total Property, Plant and Equipment	$ 54,396	$ 323	$ 608	$ 590	$ 11	$ (258)	$ 55,670
Accumulated Depreciation and Amortization	18,393	-	136	219	10	(59)	18,699
Total Property, Plant and Equipment - Net	$ 36,003	$ 323	$ 472	$ 371	$ 1	$ (199)	$ 36,971
Total Assets	$ 50,093	$ 594	$ 659	$ 868	$ 16,751	$ (16,742) (c)	$ 52,223
Investments in Equity Method Investees	24	256	17	-	2	-	299

(a) All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations, which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility, which ended in the fourth quarter of 2011.

(b) Includes eliminations due to an intercompany capital lease.
(c) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

We are 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 us due to changes in the underlying market prices or rates. We manage these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

Our strategy surrounding the use of derivative instruments primarily focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. Our 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 we transact. To accomplish our objectives, we primarily employ 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.

We enter 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 our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors.

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

Notional Volume of Derivative Instruments

	Volume		
	December 31,		Unit of
Primary Risk Exposure	**2012**	**2011**	**Measure**
	(in millions)		
Commodity:			
Power	498	609	MWhs
Coal	10	21	Tons
Natural Gas	147	100	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 235	$ 226	USD
Interest Rate and Foreign Currency	$ 1,199	$ 907	USD

Fair Value Hedging Strategies

We enter 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 our exposure to interest rate risk by converting a portion of our 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

We enter into and designate 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. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. Our 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. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we 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. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR 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 our derivative instruments, we also apply 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 our 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 our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are 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, we netted $7 million and $26 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $50 million and $133 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 our 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 (c)
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**			
			(in millions)			
Current Risk Management Assets	$ 589	$ 32	$ 3	$ 624	$ (433)	$ 191
Long-term Risk Management Assets	528	5	1	534	(166)	368
Total Assets	1,117	37	4	1,158	(599)	559
Current Risk Management Liabilities	546	43	35	624	(469)	155
Long-term Risk Management Liabilities	383	6	6	395	(181)	214
Total Liabilities	929	49	41	1,019	(650)	369
Total MTM Derivative Contract Net Assets (Liabilities)	$ 188	$ (12)	$ (37)	$ 139	$ 51	$ 190

Fair Value of Derivative Instruments
December 31, 2011

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**			
			(in millions)			
Current Risk Management Assets	$ 852	$ 24	$ -	$ 876	$ (683)	$ 193
Long-term Risk Management Assets	641	15	-	656	(253)	403
Total Assets	1,493	39	-	1,532	(936)	596
Current Risk Management Liabilities	847	29	20	896	(746)	150
Long-term Risk Management Liabilities	483	15	22	520	(325)	195
Total Liabilities	1,330	44	42	1,416	(1,071)	345
Total MTM Derivative Contract Net Assets (Liabilities)	$ 163	$ (5)	$ (42)	$ 116	$ 135	$ 251

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

The table below presents our activity of derivative risk management contracts for the years ended December 31, 2012, 2011 and 2010:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2012	2011	2010
		(in millions)	
Utility Operations Revenues	$ 21	$ 46	$ 85
Other Revenues	39	20	9
Regulatory Assets (a)	(43)	(22)	(9)
Regulatory Liabilities (a)	8	(3)	38
Total Gain (Loss) on Risk Management Contracts	$ 25	$ 41	$ 123

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

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

Our 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, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions 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 impacts Net Income during the period of change.

We record 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 Expense on the statements of income. During 2012, the fair value changes for both our hedging instruments and hedged long-term debt were immaterial. During 2011 and 2010, we recognized gains of $3 million and $6 million, respectively, on our hedging instruments and offsetting losses of $6 million and $6 million, respectively, on our long-term debt. For 2012, 2011 and 2010, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded 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 Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale 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, 2011 and 2010, we designated power, coal and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2012, 2011 and 2010, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2012, 2011 and 2010, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2012, 2011 and 2010, we designated foreign currency derivatives as cash flow hedges.

During 2012, 2011 and 2010, 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 (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2012, 2011 and 2010. 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 and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)
Changes in Fair Value Recognized in AOCI	(15)	(14)	(29)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(5)	-	(5)
Purchased Electricity for Resale	13	-	13
Other Operation Expense	-	-	-
Maintenance Expense	-	-	-
Interest Expense	-	4	4
Property, Plant and Equipment	-	-	-
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ (38)

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11
Changes in Fair Value Recognized in AOCI	(5)	(28)	(33)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	3	-	3
Other Revenues	(5)	-	(5)
Purchased Electricity for Resale	(2)	-	(2)
Other Operation Expense	(1)	-	(1)
Maintenance Expense	(1)	-	(1)
Interest Expense	-	4	4
Property, Plant and Equipment	(1)	-	(1)
Regulatory Assets (a)	2	-	2
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)
Changes in Fair Value Recognized in AOCI	9	13	22
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Utility Operations Revenues	-	-	-
Other Revenues	(7)	-	(7)
Purchased Electricity for Resale	4	-	4
Other Operation Expense	-	-	-
Maintenance Expense	-	-	-
Interest Expense	-	4	4
Property, Plant and Equipment	-	-	-
Regulatory Assets (a)	3	-	3
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11

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

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) 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 and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 24	$ -	$ 24
Hedging Liabilities (a)	36	37	73
AOCI Gain (Loss) Net of Tax	(8)	(30)	(38)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(8)	(4)	(12)

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 20	$ -	$ 20
Hedging Liabilities (a)	25	42	67
AOCI Gain (Loss) Net of Tax	(3)	(20)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(3)	(2)	(5)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) 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 we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 33 months.

Credit Risk

We limit credit risk in our 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. We use 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.

We use 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 our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our 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 our competitive retail auction loads, we are obligated to post an additional amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. AEP and its subsidiaries have not experienced a downgrade below investment grade. The following table represents: (a) our fair value of such derivative contracts, (b) the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our 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 millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 7	$ 32
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	32	39
Amount Attributable to RTO and ISO Activities	31	38

In addition, a majority of our 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, our risk management organization assesses the appropriateness of these cross-default provisions in our 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 we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of December 31, 2012 and 2011:

	December 31, 2012	December 31, 2011
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 469	$ 515
Amount of Cash Collateral Posted	8	56
Additional Settlement Liability if Cross Default Provision is Triggered	328	291

10. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

The book values and fair values of 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 millions)			
Long-term Debt	$ 17,757	$ 20,907	$ 16,516	$ 19,259

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds, marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2012			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 241	$ -	$ -	$ 241
Fixed Income Securities:				
Mutual Funds	65	2	-	67
Equity Securities - Mutual Funds	10	6	-	16
Total Other Temporary Investments	$ 316	$ 8	$ -	$ 324

	December 31, 2011			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 216	$ -	$ -	$ 216
Fixed Income Securities:				
Mutual Funds	64	-	-	64
Equity Securities - Mutual Funds	11	3	-	14
Total Other Temporary Investments	$ 291	$ 3	$ -	$ 294

(a) Primarily represents amounts held for the payment of debt.

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31,		
	2012	**2011**	**2010**
		(in millions)	
Proceeds from Investment Sales	$ -	$ 268	$ 455
Purchases of Investments	2	154	503
Gross Realized Gains on Investment Sales	-	4	16
Gross Realized Losses on Investment Sales	-	-	-

As of December 31, 2012 and 2011, we had no Other Temporary Investments with an unrealized loss position. As of December 31, 2012, fixed income securities are primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

The following table provides details of Other Temporary Investments included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes for the years ended December 31, 2012 and 2011. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Other Temporary Investments
Years Ended December 31, 2012 and 2011

	(in millions)
Balance in AOCI as of December 31, 2010	$ 4
Changes in Fair Value Recognized in AOCI	1
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:	
Interest Income	(3)
Balance in AOCI as of December 31, 2011	2
Changes in Fair Value Recognized in AOCI	2
Balance in AOCI as of December 31, 2012	$ 4

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments as of December 31, 2012 and December 31, 2011:

	December 31, 2012			December 31, 2011		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 17	$ -	$ -	$ 18	$ -	$ -
Fixed Income Securities:						
United States Government	648	58	(1)	544	61	(1)
Corporate Debt	35	5	(1)	54	5	(2)
State and Local Government	270	1	(1)	330	-	(2)
Subtotal Fixed Income Securities	953	64	(3)	928	66	(5)
Equity Securities - Domestic	736	285	(77)	646	215	(80)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,706	$ 349	$ (80)	$ 1,592	$ 281	$ (85)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2012, 2011 and 2010:

	Years Ended December 31, 2012	2011	2010
	(in millions)		
Proceeds from Investment Sales	$ 988	$ 1,111	$ 1,362
Purchases of Investments	1,045	1,167	1,415
Gross Realized Gains on Investment Sales	25	33	12
Gross Realized Losses on Investment Sales	9	22	2

The adjusted cost of debt securities was $889 million and $862 million as of December 31, 2012 and 2011, respectively. The adjusted cost of equity securities was $451 million and $431 million as of December 31, 2012 and 2011, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2012 was as follows:

	Fair Value of Debt Securities (in millions)
Within 1 year	$ 81
1 year – 5 years	373
5 years – 10 years	266
After 10 years	233
Total	$ 953

Fair Value Measurements of Financial Assets and Liabilities

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

The following tables set forth, by level within the fair value hierarchy, our 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. Our 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 our valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ 1	$ -	$ 272	$ 279
Other Temporary Investments					
Restricted Cash (a)	227	5	-	9	241
Fixed Income Securities:					
Mutual Funds	67	-	-	-	67
Equity Securities - Mutual Funds (b)	16	-	-	-	16
Total Other Temporary Investments	310	5	-	9	324
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	47	938	131	(599)	517
Cash Flow Hedges:					
Commodity Hedges (c)	8	28	-	(12)	24
Fair Value Hedges	-	2	-	2	4
De-designated Risk Management Contracts (e)	-	-	-	14	14
Total Risk Management Assets	55	968	131	(595)	559
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	7	-	-	10	17
Fixed Income Securities:					
United States Government	-	648	-	-	648
Corporate Debt	-	35	-	-	35
State and Local Government	-	270	-	-	270
Subtotal Fixed Income Securities	-	953	-	-	953
Equity Securities - Domestic (b)	736	-	-	-	736
Total Spent Nuclear Fuel and Decommissioning Trusts	743	953	-	10	1,706
Total Assets	$ 1,114	$ 1,927	$ 131	$ (304)	$ 2,868
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 45	$ 838	$ 45	$ (636)	$ 292
Cash Flow Hedges:					
Commodity Hedges (c)	-	48	-	(12)	36
Interest Rate/Foreign Currency Hedges	-	37	-	-	37
Fair Value Hedges	-	2	-	2	4
Total Risk Management Liabilities	$ 45	$ 925	$ 45	$ (646)	$ 369

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ -	$ -	$ 215	$ 221
Other Temporary Investments					
Restricted Cash (a)	191	-	-	25	216
Fixed Income Securities:					
Mutual Funds	64	-	-	-	64
Equity Securities - Mutual Funds (b)	14	-	-	-	14
Total Other Temporary Investments	269	-	-	25	294
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	47	1,299	147	(945)	548
Cash Flow Hedges:					
Commodity Hedges (c)	15	23	-	(18)	20
De-designated Risk Management Contracts (e)	-	-	-	28	28
Total Risk Management Assets	62	1,322	147	(935)	596
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	-	5	-	13	18
Fixed Income Securities:					
United States Government	-	544	-	-	544
Corporate Debt	-	54	-	-	54
State and Local Government	-	330	-	-	330
Subtotal Fixed Income Securities	-	928	-	-	928
Equity Securities - Domestic (b)	646	-	-	-	646
Total Spent Nuclear Fuel and Decommissioning Trusts	646	933	-	13	1,592
Total Assets	$ 983	$ 2,255	$ 147	$ (682)	$ 2,703
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 43	$ 1,209	$ 78	$ (1,052)	$ 278
Cash Flow Hedges:					
Commodity Hedges (c)	-	43	-	(18)	25
Interest Rate/Foreign Currency Hedges	-	42	-	-	42
Total Risk Management Liabilities	$ 43	$ 1,294	$ 78	$ (1,070)	$ 345

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) 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."

(d) The December 31, 2012 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $9 million in 2013, $(3) million in periods 2014-2016 and ($4) million in periods 2017-2018; Level 2 matures $16 million in 2013, $61 million in periods 2014-2016, $16 million in periods 2017-2018 and $7 million in periods 2019-2030; Level 3 matures $18 million in 2013, $31 million in periods 2014-2016, $13 million in periods 2017-2018 and $24 million in periods 2019-2030. Risk management commodity contracts are substantially comprised of power contracts.

(e) 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.

(f) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(g) The December 31, 2011 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $3 million in 2012, $7 million in periods 2013-2015 and ($6) million in periods 2016-2018; Level 2 matures $21 million in 2012, $50 million in periods 2013-2015, $11 million in periods 2016-2017 and $8 million in periods 2018-2030; Level 3 matures ($19) million in 2012, $44 million in periods 2013-2015, $18 million in periods 2016-2017 and $26 million in periods 2018-2030. Risk management commodity contracts are substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2012, 2011 and 2010.

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 millions)
Balance as of December 31, 2011	$ 69
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(15)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	29
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	32
Transfers into Level 3 (d) (e)	1
Transfers out of Level 3 (e) (f)	(35)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	5
Balance as of December 31, 2012	$ 86

Year Ended December 31, 2011	**Net Risk Management Assets (Liabilities)**
	(in millions)
Balance as of December 31, 2010	$ 85
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(10)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	9
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(3)
Transfers into Level 3 (d) (e)	13
Transfers out of Level 3 (e) (f)	(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(13)
Balance as of December 31, 2011	$ 69

Year Ended December 31, 2010	**Net Risk Management Assets (Liabilities)**
	(in millions)
Balance as of December 31, 2009	$ 62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	63
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(25)
Transfers into Level 3 (d) (e)	18
Transfers out of Level 3 (e) (f)	(53)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2010	$ 85

(a) Included in revenues on the 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 the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

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

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High
	(in millions)					
Energy Contracts	$ 124	$ 38	Discounted Cash Flow	Forward Market Price (a)	$ 9.40	$ 111.97
				Counterparty Credit Risk (b)	397	
FTRs	7	7	Discounted Cash Flow	Forward Market Price (a)	(3.21)	14.79
Total	$ 131	$ 45				

(a) Represents market prices in dollars per MWh.
(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

11. INCOME TAXES

The details of our consolidated income taxes before extraordinary item as reported are as follows:

	Years Ended December 31, 2012	2011	2010
	(in millions)		
Federal:			
Current	$ (52)	$ 20	$ (134)
Deferred	698	786	760
Total Federal	646	806	626
State and Local:			
Current	35	37	(20)
Deferred	(77)	(25)	38
Total State and Local	(42)	12	18
International:			
Current	-	-	(1)
Deferred	-	-	-
Total International	-	-	(1)
Income Tax Expense	$ 604	$ 818	$ 643

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

	Years Ended December 31, 2012	2011	2010
		(in millions)	
Net Income	$ 1,262	$ 1,949	$ 1,218
Extraordinary Item, Net of Tax of $(112) million in 2011	-	(373)	-
Income Before Extraordinary Item	1,262	1,576	1,218
Income Tax Expense	604	818	643
Pretax Income	$ 1,866	$ 2,394	$ 1,861
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 653	$ 838	$ 651
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	39	41	47
Investment Tax Credits, Net	(14)	(15)	(16)
Energy Production Credits	-	(18)	(20)
State and Local Income Taxes, Net	(33)	(22)	11
Removal Costs	(18)	(20)	(19)
AFUDC	(39)	(42)	(33)
Medicare Subsidy	3	1	12
Valuation Allowance	6	86	-
Tax Reserve Adjustments	17	2	(16)
Other	(10)	(33)	26
Income Tax Expense	$ 604	$ 818	$ 643
Effective Income Tax Rate	32.4 %	34.2 %	34.6 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2012	2011
	(in millions)	
Deferred Tax Assets	$ 2,900	$ 2,855
Deferred Tax Liabilities	(12,098)	(11,185)
Net Deferred Tax Liabilities	$ (9,198)	$ (8,330)
Property Related Temporary Differences	$ (6,752)	$ (5,963)
Amounts Due from Customers for Future Federal Income Taxes	(289)	(259)
Deferred State Income Taxes	(683)	(668)
Securitized Transition Assets	(780)	(621)
Regulatory Assets	(781)	(1,208)
Postretirement Benefits	266	424
Accrued Pensions	104	149
Deferred Income Taxes on Other Comprehensive Loss	184	254
Accrued Nuclear Decommissioning	(475)	(436)
Net Operating Loss Carryforward	194	125
Tax Credit Carryforward	104	182
Valuation Allowance	(92)	(86)
All Other, Net	(198)	(223)
Net Deferred Tax Liabilities	$ (9,198)	$ (8,330)

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	)	
A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	**Case No. 2014-00396**
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

SECTION II

FILING REQUIREMENTS

VOLUME 4 OF 5

December 23, 2014

AEP System Tax Allocation Agreement

We, along with our subsidiaries, file a consolidated federal income tax return. 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 our 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

We are no longer subject to U.S. federal examination for years before 2009. We 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 materially impact 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, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. We believe that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2008. In March 2012, we settled all outstanding franchise tax issues with the state of Ohio for the years 2000 through 2009. The settlements did not materially impact net income, cash flows or financial condition.

Net Income Tax Operating Loss Carryforward

In 2012 and 2011, we recognized federal net income tax operating losses of $366 million and $226 million, respectively, driven primarily by bonus depreciation, pension plan contributions and other book-versus-tax temporary differences. We also had state net income tax operating loss carryforwards as indicated in the table below.

State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
	(in millions)	
Louisiana	$ 314	2027
Oklahoma	137	2031
Tennessee	13	2026
Virginia	329	2031
West Virginia	897	2032

As a result, we accrued deferred federal, state and local income tax benefits in 2012 and 2011. We expect to realize the federal, state and local cash flow benefits in future periods as there was insufficient capacity in prior periods to carry the net operating losses back. We anticipate future taxable income will be sufficient to realize the net income tax operating loss tax benefits before the federal carryforward expires after 2032.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2012, 2011 and 2009, along with lower federal and state taxable income in 2010, resulted in unused federal and state income tax credits. As of December 31, 2012, we have total federal tax credit carryforwards of $104 million and total state tax credit carryforwards of $82 million, not all of which are subject to an expiration date. If these credits are not utilized, the federal general business tax credits of $70 million will expire in the years 2028 through 2031 and the state coal tax credits of $29 million will expire in the years 2013 through 2021.

We anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. We do not anticipate state taxable income will be sufficient in future periods to realize the tax benefits of all state income tax credits before they expire and we have provided a valuation allowance accordingly.

Valuation Allowance

We assess past results and future operations to estimate and evaluate available positive and negative evidence to evaluate whether sufficient future taxable income will be generated to use existing deferred tax assets. A significant piece of objective negative information evaluated was the net income tax operating losses sustained in 2012, 2011 and 2009. On the basis of this evaluation of available positive and negative evidence, as of December 31, 2012, a valuation allowance of $36 million for state tax credits, net of federal tax, and $56 million for an unrealized capital loss has been recorded in order to measure only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets considered realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are materially impacted or if objective negative evidence in the form of cumulative losses is no longer present and additional weight may be given to subjective evidence, such as our projections for growth.

For a discussion of the tax implications of the unrealized capital loss resulting from our settlement with BOA and Enron, see "Enron Bankruptcy" section of Note 6.

Uncertain Tax Positions

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation expense 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**	**2010**
		(in millions)	
Interest Expense	$ 11	$ 8	$ 8
Interest Income	-	22	11
Reversal of Prior Period Interest Expense	1	13	5

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 millions)	
Accrual for Receipt of Interest	$ -	$ 13
Accrual for Payment of Interest and Penalties	7	6

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

	2012	**2011**	**2010**
		(in millions)	
Balance as of January 1,	$ 168	$ 219	$ 237
Increase - Tax Positions Taken During a Prior Period	23	51	40
Decrease - Tax Positions Taken During a Prior Period	(16)	(43)	(43)
Increase - Tax Positions Taken During the Current Year	121	10	-
Decrease - Tax Positions Taken During the Current Year	-	-	(6)
Decrease - Settlements with Taxing Authorities	(25)	(31)	(2)
Decrease - Lapse of the Applicable Statute of Limitations	(4)	(38)	(7)
Balance as of December 31,	$ 267	$ 168	$ 219

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $149 million, $111 million and $112 million for 2012, 2011 and 2010, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not materially impact net income or financial condition. However, the bonus depreciation contributed to the 2009 federal net operating tax loss that resulted in a 2010 cash flow benefit of $419 million.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Due to the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction did not materially impact cash flows or financial condition. For the year ended December 31, 2010, deferred tax assets decreased $56 million, partially offset by recording net tax regulatory assets of $35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of $21 million.

The Small Business Jobs Act (the 2010 Act) was enacted in September 2010. Included in the 2010 Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the 2010 Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2011 and 2010. The enacted provisions will not materially impact net income or financial condition but had a favorable impact on cash flows of $318 million in 2010.

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. We 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 net income or financial condition but are expected to have a favorable impact on cash flows in 2013.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rates from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

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 net income, cash flows or financial condition.

12. LEASES

Leases of property, plant and equipment are for periods up to 60 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 Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2012	2011	2010
		(in millions)	
Net Lease Expense on Operating Leases	$ 346	$ 343	$ 343
Amortization of Capital Leases	73	72	97
Interest on Capital Leases	29	32	26
Total Lease Rental Costs	$ 448	$ 447	$ 466

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

Property, Plant and Equipment Under Capital Leases	December 31, 2012	2011
	(in millions)	
Generation	$ 117	$ 104
Other Property, Plant and Equipment	495	485
Total Property, Plant and Equipment Under Capital Leases	612	589
Accumulated Amortization	173	137
Net Property, Plant and Equipment Under Capital Leases	$ 439	$ 452
Obligations Under Capital Leases		
Noncurrent Liability	$ 375	$ 384
Liability Due Within One Year	74	74
Total Obligations Under Capital Leases	$ 449	$ 458

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

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2013	$ 95	$ 302
2014	79	275
2015	65	257
2016	59	233
2017	63	219
Later Years	244	1,034
Total Future Minimum Lease Payments	605	$ 2,320
Less Estimated Interest Element	156	
Estimated Present Value of Future Minimum Lease Payments	$ 449	

Master Lease Agreements

We lease 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, we are 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 $19 million assuming the fair value of the equipment is zero at the end of the lease term. Obligations under these master lease agreements are included in the future minimum lease payments schedule earlier in this note.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2012 are as follows:

Future Minimum Lease Payments	**AEGCo**	**I&M**
	(in millions)	
2013	$ 74	$ 74
2014	74	74
2015	74	74
2016	74	74
2017	74	74
Later Years	369	369
Total Future Minimum Lease Payments	$ 739	$ 739

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $14 million for I&M and $15 million for SWEPCo for the remaining railcars as of December 31, 2012. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five-year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $12 million and SWEPCo's is approximately $13 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2012 and 2011 balance sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2012 and 2011 balance sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $85 million. The lease had a variable rate based on one month LIBOR and was accounted for as a capital lease with lease terms up to 60 months. This lease was terminated with the March 2012 refueling.

13. FINANCING ACTIVITIES

AEP Common Stock

Listed below is a reconciliation of common stock share activity for the years ended December 31, 2012, 2011 and 2010:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, December 31, 2009	498,333,265	20,278,858
Issued	2,781,616	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2010	501,114,881	20,307,725
Issued	2,644,579	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2011	503,759,460	20,336,592
Issued	2,245,502	-
Balance, December 31, 2012	506,004,962	20,336,592

Preferred Stock

In December 2011, AEP subsidiaries redeemed all of their outstanding preferred stock with a par value of $60 million at a premium, resulting in a $2.8 million loss, which is included in Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense on the statement of income.

Long-term Debt

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

Type of Debt and 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 millions)	
Senior Unsecured Notes (a)					
2012-2042	5.46%	0.685%-8.13%	0.955%-8.13%	$ 12,712	$ 11,737
Pollution Control Bonds (b)					
2012-2038 (c)	3.58%	0.11%-6.30%	0.06%-6.30%	1,958	2,112
Notes Payable (d)					
2012-2032	4.35%	1.913%-8.03%	2.029%-8.03%	427	402
Securitization Bonds (e)					
2013-2024	4.21%	0.88%-6.25%	4.98%-6.25%	2,281	1,688
Junior Subordinated Debentures (a)					
2063			8.75%	-	315
Spent Nuclear Fuel Obligation (f)				265	265
Other Long-term Debt (g)					
2015-2059	2.63%	1.72%-13.718%	3.00%-13.718%	140	29
Fair Value of Interest Rate Hedges				3	7
Unamortized Discount, Net				(29)	(39)
Total Long-term Debt Outstanding				17,757	16,516
Long-term Debt Due Within One Year				2,171	1,433
Long-term Debt				$ 15,586	$ 15,083

(a) In 2012, AEP issued $850 million of Senior Unsecured Notes used to retire $243 million of Senior Unsecured Notes and $315 million of Junior Subordinated Debentures.
(b) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.
(c) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on the balance sheets.
(d) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.
(e) In 2012, AEP Texas Central Transition Funding III LLC issued $800 million of Securitization Bonds (see Note 15).
(f) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 5).
(g) In 2012, I&M issued a $110 million three-year credit facility to be used for general corporate purposes.

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

	2013	2014	2015	2016	2017	After 2017	Total
				(in millions)			
Principal Amount	$ 2,171	$ 1,169	$ 1,438	$ 840	$ 1,655	$ 10,513	$ 17,786
Unamortized Discount, Net							(29)
Total Long-term Debt Outstanding							$ 17,757

In January 2013 and February 2013, I&M retired $12 million and $11 million, respectively, of Notes Payable related to DCC Fuel.

In January 2013, TCC retired $105 million of its outstanding Securitization Bonds.

In February 2013, OPCo retired $250 million of 5.5% Senior Unsecured Notes due in 2013.

As of December 31, 2012, trustees held, on our behalf, $583 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

Utility Subsidiaries' Restrictions

Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. As of December 31, 2012, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $6 billion.

The Federal Power Act prohibits the utility subsidiaries 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 the utility subsidiaries to pay dividends out of retained earnings.

Lines of Credit and Short-term Debt

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2012, we had credit facilities totaling $3.25 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2012 was $1.2 billion and the weighted average interest rate of commercial paper outstanding during 2012 was 0.44%. Our outstanding short-term debt was as follows:

	December 31,			
	2012		2011	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		**(in millions)**	
Securitized Debt for Receivables (b)	$ 657	0.26 %	$ 666	0.27 %
Commercial Paper	321	0.42 %	967	0.51 %
Line of Credit – Sabine (c)	3	1.82 %	17	1.79 %
Total Short-term Debt	$ 981		$ 1,650	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

For a discussion of credit facilities, see "Letters of Credit" section of Note 5.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

In 2012, we renewed AEP Credit's 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.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2012	**2011**	**2010**
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	0.26 %	0.27 %	0.31 %
Net Uncollectible Accounts Receivable Written Off	$ 29	$ 37	$ 22

	December 31,	
	2012	**2011**
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 835	$ 902
Total Principal Outstanding	657	666
Delinquent Securitized Accounts Receivable	37	38
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	21	18
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	316	370

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

14. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards, including stock options, to employees. A maximum of 10,000,000 shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. As of December 31, 2012, 17,907,559 shares remained available for issuance under the LTIP plan. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2012, 2011 or 2010 but we do have outstanding stock options from grants in earlier periods that were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1 of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total intrinsic value of options exercised is as follows:

Stock Options	Years Ended December 31, 2012	2011	2010
	(in thousands)		
Intrinsic Value of Options Exercised (a)	$ 1,699	$ 1,202	$ 2,058

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2012, 2011 and 2010 is as follows:

	2012		2011		2010	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding as of January 1,	321	$ 29.35	551	$ 32.88	1,089	$ 32.78
Granted	-	NA	-	NA	-	NA
Exercised/Converted	(128)	28.21	(104)	27.39	(448)	31.53
Forfeited/Expired	(5)	27.26	(126)	46.40	(90)	38.44
Outstanding as of December 31,	188	30.17	321	29.35	551	32.88
Options Exercisable as of December 31,	188	$ 30.17	321	$ 29.35	551	$ 32.88

NA Not applicable.

The following table summarizes information about AEP stock options outstanding and exercisable as of December 31, 2012:

2012 Range of Exercise Prices	Number of Options Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.95 - $30.76	188	0.99	$ 30.17	$ 2,358

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee. Performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP Career Shares are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We record compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on the balance sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2012, 2011 and 2010 as follows:

Performance Units	Years Ended December 31, 2012	2011	2010
Awarded Units (in thousands)	546	7	736
Weighted Average Unit Fair Value at Grant Date	$ 41.38	$ 38.39	$ 35.43
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2012	2011	2010
Awarded Units (in thousands)	138	198	211
Weighted Average Grant Date Fair Value	$ 40.97	$ 37.31	$ 34.70
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant but are not paid in cash until after the participant's termination of employment.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the number of performance units earned but may not increase the number earned. The performance scores for all open performance periods prior to those granted in 2012 are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the electric utility and multi utility sub-industry segments of the Standard and Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target. For the performance units granted in 2012, the three-year total shareholder return peer group was changed to the S&P 500 Electric Utility Index.

The certified performance scores and units earned for the three-year period ended December 31, 2012, 2011 and 2010 were as follows:

Performance Units	Years Ended December 31, 2012	2011	2010
Certified Performance Score	99.7 %	89.8 %	55.8 %
Performance Units Earned	1,096,572	1,216,926	489,013
Performance Units Mandatorily Deferred as AEP Career Shares	51,056	52,639	33,501
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	26,337	42,502	6,583
Performance Units to be Paid in Cash	1,019,179	1,121,785	448,929

The cash payouts for the years ended December 31, 2012, 2011 and 2010 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2012	2011	2010
		(in thousands)	
Cash Payouts for Performance Units	$ 44,968	$ 15,985	$ 18,683
Cash Payouts for AEP Career Share Distributions	11,027	2,777	3,594

Restricted Shares and Restricted Stock Units

In 2004, the independent members of the AEP Board of Directors granted 300,000 restricted shares to the then Chairman, President and CEO upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005, 50,000 vested on January 1, 2006, 66,666 vested on November 30, 2009, 66,667 vested on November 30, 2010 and 66,667 vested on November 30, 2011. Compensation cost for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market closing price, which was $30.76. The maximum contractual term for these restricted shares was eight years and dividends on these restricted shares were paid in cash. AEP has not granted other restricted shares.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. Additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. Compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market closing price. The maximum contractual term of outstanding RSUs is six years from the grant date.

In 2010, the HR Committee granted a total of 165,520 RSUs to four CEO succession candidates as a retention incentive for these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2012, 2011 and 2010 as follows:

	Years Ended December 31,		
Restricted Stock Units	**2012**	**2011**	**2010**
Awarded Units (in thousands)	497	121	873
Weighted Average Grant Date Fair Value	$ 40.69	$ 37.07	$ 35.24

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
Restricted Shares and Restricted Stock Units	**2012**	**2011**	**2010**
		(in thousands)	
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 10,608	$ 7,164	$ 6,044
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	12,157	8,017	5,993

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of our nonvested RSUs as of December 31, 2012 and changes during the year ended December 31, 2012 are as follows:

Nonvested Restricted Stock Units	**Shares/Units**	**Weighted Average Grant Date Fair Value**
	(in thousands)	
Nonvested as of January 1, 2012	903	$ 35.46
Granted	497	40.69
Vested	(306)	34.64
Forfeited	(94)	35.95
Nonvested as of December 31, 2012	1,000	38.22

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2012 was $43 million and the weighted average remaining contractual life was 2.14 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to non-employee directors are fully vested upon grant date. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date.

We record compensation cost for stock units when the units are awarded and adjust the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2012, 2011 and 2010.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2012, 2011 and 2010 as follows:

	Years Ended December 31,		
Stock Unit Accumulation Plan for Non-Employee Directors	**2012**	**2011**	**2010**
Awarded Units (in thousands)	52	52	54
Weighted Average Grant Date Fair Value	$ 41.20	$ 37.72	$ 34.67

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2012**	**2011**	**2010**
		(in thousands)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 51,767	$ 61,807	$ 28,116
Actual Tax Benefit Realized	18,119	21,632	9,841
Total Compensation Cost Capitalized	10,707	11,608	4,689

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

During the years ended December 31, 2012, 2011 and 2010, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2012, there was $47 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.53 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2012, 2011 and 2010 were as follows:

	Years Ended December 31,		
Share-based Compensation Plans	**2012**	**2011**	**2010**
		(in thousands)	
Cash Received from Stock Options Exercised	$ 3,598	$ 2,855	$ 14,134
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	618	411	706

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we are permitted to use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset our tax withholding obligation.

In February 2013, the HR Committee granted approximately $40 million in share-based awards. This amount will be allocated between 2013-2015 performance units and restricted stock units vesting over 40 months.

15. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. We believe that significant assumptions and judgments were applied consistently.

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding and a protected cell of EIS. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, Transition Funding, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2012, 2011 and 2010 were $147 million, $128 million and $133 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the balance sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the years ended December 31, 2012, 2011 and 2010 were $32 million, $48 million and $35 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

I&M has nuclear fuel lease agreements with DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC and DCC Fuel V LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2012, 2011 and 2010 were $127 million, $85 million and $59 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on the balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 13.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $2.3 billion and $1.7 billion as of December 31, 2012 and 2011, respectively, and are included in current and long-term debt on the balance sheets. Transition Funding has securitized transition assets of $2.1 billion and $1.6 billion as of December 31, 2012 and 2011, respectively, which are presented separately on the face of the balance sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 57	$ 133	$ 130	$ 843	$ 250
Net Property, Plant and Equipment	170	176	-	-	-
Other Noncurrent Assets	55	92	4	1	2,167 (a)
Total Assets	$ 282	$ 401	$ 134	$ 844	$ 2,417
LIABILITIES AND EQUITY					
Current Liabilities	$ 32	$ 121	$ 43	$ 800	$ 304
Noncurrent Liabilities	250	280	66	1	2,095
Equity	-	-	25	43	18
Total Liabilities and Equity	$ 282	$ 401	$ 134	$ 844	$ 2,417

(a) Includes an intercompany item eliminated in consolidation of $89 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2011
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	TCC Transition Funding
ASSETS					
Current Assets	$ 48	$ 118	$ 121	$ 910	$ 220
Net Property, Plant and Equipment	154	188	-	-	-
Other Noncurrent Assets	42	118	6	1	1,580
Total Assets	$ 244	$ 424	$ 127	$ 911	$ 1,800
LIABILITIES AND EQUITY					
Current Liabilities	$ 68	$ 103	$ 40	$ 864	$ 229
Noncurrent Liabilities	176	321	71	1	1,557
Equity	-	-	16	46	14
Total Liabilities and Equity	$ 244	$ 424	$ 127	$ 911	$ 1,800

DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2012, 2011 and 2010 were $77 million, $62 million and $56 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on the balance sheets.

Our investment in DHLC was:

	December 31,			
	2012		2011	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 8	$ 8
Retained Earnings	1	1	1	1
SWEPCo's Guarantee of Debt	-	49	-	52
Total Investment in DHLC	$ 9	$ 58	$ 9	$ 61

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In November 2012, the FERC issued an order accepting AEP's and FirstEnergy's abandonment cost recovery filing which requested authority to recover prudently-incurred costs associated with the PATH Project. The FERC also set the issue of prudency of costs for settlement proceedings.

Our investment in PATH-WV was:

	December 31,			
	2012		2011	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 19	$ 19	$ 19	$ 19
Retained Earnings	12	12	10	10
Total Investment in PATH-WV	$ 31	$ 31	$ 29	$ 29

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide the annual property information:

2012	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 16,973	$ 6,962	1.7 - 3.8 %	31 - 132	$ 9,306	$ 3,526	2.6 - 3.3 %	35 - 66
Transmission	9,846	2,720	1.2 - 2.8 %	25 - 87	-	-	NA	NA
Distribution	15,565	3,837	2.4 - 3.9 %	11 - 75	-	-	NA	NA
CWIP	1,600	(27)	NM	NM	219	1	NM	NM
Other	2,644	1,238	1.8 - 9.6 %	5 - 75	1,301	434	NM	NM
Total	$ 46,628	$ 14,730			$ 10,826	$ 3,961		

2011	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
	(in millions)			(in years)	(in millions)			(in years)
Generation	$ 14,804	$ 6,692	1.6 - 3.8 %	9 - 132	$ 10,134	$ 3,904	2.6 - 3.5 %	20 - 66
Transmission	9,048	2,600	1.3 - 2.7 %	25 - 87	-	-	NA	NA
Distribution	14,783	3,828	2.4 - 4.0 %	11 - 75	-	-	NA	NA
CWIP	2,913 (a)	36	NM	NM	208	1	NM	NM
Other	2,587	1,246	1.7 - 9.3 %	5 - 55	1,193	392	NM	NM
Total	$ 44,135	$ 14,402			$ 11,535	$ 4,297		

2010	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)
Generation	1.6 - 3.8 %	9 - 132	2.2 - 5.1 %	20 - 70
Transmission	1.4 - 3.0 %	25 - 87	NA	NA
Distribution	2.4 - 3.9 %	11 - 75	NA	NA
CWIP	NM	NM	NM	NM
Other	3.0 - 12.5 %	5 - 55	NM	NM

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.
NA Not applicable.
NM Not meaningful.

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

For rate-regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2012 and 2011 aggregate carrying amounts of ARO:

	Carrying Amount of ARO
	(in millions)
ARO as of December 31, 2010	$ 1,398
Accretion Expense	82
Liabilities Incurred	7
Liabilities Settled	(26)
Revisions in Cash Flow Estimates	13
ARO as of December 31, 2011 (a)	1,474
Accretion Expense	85
Liabilities Incurred	17
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	144
ARO as of December 31, 2012	$ 1,696

(a) The current portion of our ARO, totaling $2 million, is included in Other Current Liabilities on our 2011 balance sheet.

As of December 31, 2012 and 2011, our ARO liability was $1.7 billion and $1.5 billion, respectively, and included $1.2 billion and $979 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2012 and 2011, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.4 billion and $1.3 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2012	2011	2010
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 93	$ 98	$ 77
Allowance for Borrowed Funds Used During Construction	69	63	53

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and the investments and accumulated depreciation are reflected on the balance sheets under Property, Plant and Equipment as follows:

			Company's Share as of December 31, 2012		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ -	$ -	$ -
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	310	26	59
J.M. Stuart Generating Station (c)	Coal	26.0 %	542	11	181
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	807	2	387
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2 %	263	8	195
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0 %	121	14	64
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9 %	514	16	371
Oklaunion Generating Station (Unit No. 1) (f)	Coal	70.3 %	403	4	216
Turk Generating Plant (g)	Coal	73.33 %	1,613	(3)	-
Transmission	NA	(h)	69	4	50
Total			$ 4,642	$ 82	$ 1,523

			Company's Share as of December 31, 2011		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	310	12	54
J.M. Stuart Generating Station (c)	Coal	26.0 %	529	13	172
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771	20	377
Dolet Hills Generating Station (Unit No. 1) (d)	Lignite	40.2 %	264	-	193
Flint Creek Generating Station (Unit No. 1) (e)	Coal	50.0 %	118	6	63
Pirkey Generating Station (Unit No. 1) (e)	Lignite	85.9 %	513	1	362
Oklaunion Generating Station (Unit No. 1) (f)	Coal	70.3 %	401	2	208
Turk Generating Plant (g)	Coal	73.33 %	-	1,326	-
Transmission	NA	(h)	63	6	50
Total			$ 2,988	$ 1,386	$ 1,487

(a) Operated by Duke Energy Corporation, a nonaffiliated company. AEP's portion of this unit was impaired in the fourth quarter of 2012. See "Impairments" section of Note 6.
(b) Operated by OPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Operated by CLECO, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) Operated by PSO and also jointly-owned (54.7%) by TNC.
(g) Turk Generating Plant was placed in service in December 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2012, construction costs totaling $457 million have been billed to the other owners.
(h) Varying percentages of ownership.
NA Not applicable.

17. COST REDUCTION PROGRAMS

2012 Sustainable Cost Reductions

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to conduct an organizational and process evaluation and a second firm to evaluate our 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.

We recorded a charge to expense during 2012 related to the sustainable cost reductions initiative.

	Total (in millions)
Incurred	$ 47
Settled	(22)
Balance as of December 31, 2012	$ 25

These expenses relate primarily to severance benefits. They are included primarily in Other Operation expense on the statement of income and Other Current Liabilities on the balance sheet. Approximately 95% of the expense was within the Utility Operations segment.

2010 Cost Reduction Initiatives

In April 2010, we began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions was eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Many of these eliminated positions resulted from employees that elected retirement through voluntary severance. Most of the affected employees terminated employment as of May 31, 2010. The severance program provided two weeks of base pay for every year of service along with other severance benefits.

We recorded a charge of $293 million to Other Operation expense during 2010 primarily related to severance benefits as the result of headcount reduction initiatives.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2012 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,625	$ 3,551	$ 4,156	$ 3,613
Operating Income	754	741	912	249 (a)(b)
Net Income	390	363	488	21 (a)(b)
Amounts Attributable to AEP Common Shareholders:				
Net Income	389	362	487	21 (a)(b)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05

	2011 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,730	$ 3,609	$ 4,333	$ 3,444
Operating Income	832	717	890 (c)	343 (e)
Income Before Extraordinary Item	355	353	657 (c) (d)	211 (d) (e)
Extraordinary Item, Net of Tax	-	-	273 (d)	100 (d)
Net Income	355	353	930 (c) (d)	311 (d) (e)
Amounts Attributable to AEP Common Shareholders:				
Income Before Extraordinary Item	353	352	655 (c) (d)	208 (d) (e)
Extraordinary Item, Net of Tax	-	-	273 (d)	100 (d)
Net Income	353	352	928 (c) (d)	308 (d) (e)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Item (f)	0.73	0.73	1.35	0.43
Extraordinary Item per Share	-	-	0.57	0.20
Earnings per Share (f)	0.73	0.73	1.92	0.63
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Item (f)	0.73	0.73	1.35	0.43
Extraordinary Item per Share	-	-	0.57	0.20
Earnings per Share (f)	0.73	0.73	1.92	0.63

(a) Includes pretax impairments for certain Ohio generation plants (see Note 6).
(b) See Note 17 for discussion of cost reduction programs in 2012.
(c) Includes pretax plant impairments (see Note 6) and a provision for refund of POLR charges in Ohio.
(d) See "TCC Texas Restructuring" section of Note 2 for discussion of gains recorded in the third and fourth quarters of 2011.
(e) Includes a refund of POLR charges in Ohio and OPCo adjustments for fuel disallowances, the 2010 SEET and the obligation to contribute to Partnership with Ohio and Ohio Growth Fund. Also includes a pretax plant impairment for SWEPCo's Turk Plant (see Note 6).
(f) Quarterly Earnings per Share amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.

19. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2012 and 2011 by operating segment are as follows:

	Utility Operations	AEP River Operations	Generation and Marketing	AEP Consolidated
		(in millions)		
Balance as of December 31, 2010	$ 37	$ 39	$ -	$ 76
Impairment Losses	-	-	-	-
Balance as of December 31, 2011	37	39	-	76
Acquired Goodwill	-	-	15	15
Impairment Losses	-	-	-	-
Balance as of December 31, 2012	$ 37	$ 39	$ 15	$ 91

In the fourth quarters of 2012 and 2011, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

During 2012, the increase in goodwill of $15 million was due to the acquisition of BlueStar.

Other Intangible Assets

Acquired intangible assets subject to amortization were $24 million as of December 31, 2012, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. As of December 31, 2011, all acquired intangible assets had been fully amortized. During 2012, as a result of the acquisition of BlueStar, we acquired intangible assets associated with sales contracts and customer accounts of $58 million. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2012		2011	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)		(in millions)		
Easements	10	$ -	$ -	$ 2	$ 2
Purchased Technology	10	-	-	11	11
Acquired Customer Contracts	5	58	34	-	-
Total		$ 58	$ 34	$ 13	$ 13

Amortization of intangible assets was $34 million, $1 million and $1 million for the years ended December 31, 2012, 2011 and 2010, respectively. Our estimated total amortization is $13 million, $6 million, $3 million and $2 million for 2013, 2014, 2015 and 2016, respectively.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page – Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings – Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders – (Stock held in a bank or brokerage account) – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/buyandmanagestock.

Financial Community Inquiries – Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; Julie Sherwood, 614-716-2663, jasherwood@AEP.com; or Sara Macioch, 614-716-2835, semacioch@AEP.com. Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders – As of February 25, 2013, there were approximately 81,878 registered shareholders and approximately 433,200 shareholders holding stock in street name through a bank or broker. There were 485,790,462 shares outstanding as of February 25, 2013.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2012. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	Office
Nicholas K. Akins	52	President and Chief Executive Officer
Lisa M. Barton	47	Executive Vice President – Transmission
David M. Feinberg	43	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	52	Senior Vice President and Chief Administrative Officer
Mark C. McCullough	53	Executive Vice President – Generation
Robert P. Powers	58	Executive Vice President and Chief Operating Officer
Brian X. Tierney	45	Executive Vice President and Chief Financial Officer
Dennis E. Welch	61	Executive Vice President and Chief External Officer

Appendix A to the
Proxy Statement

American Electric Power

2013 Annual Report

Audited Consolidated Financial Statements and
Management's Discussion and Analysis of Financial Condition and Results of Operations

AEP: America's Energy Partner

AMERICAN ELECTRIC POWER
1 Riverside Plaza
Columbus, Ohio 43215-2373

CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP Energy	AEP Energy, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transmission Holdco	AEP Transmission Holding Company, LLC, a wholly-owned subsidiary of AEP.
AEP West Companies	PSO, SWEPCo, TCC and TNC.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
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.
AFUDC	Allowance for Funds Used During Construction.
AGR	AEP Generation Resources Inc., a nonregulated AEP subsidiary that acquired the generation assets and liabilities of OPCo.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
Appalachian Consumer Rate Relief Funding	Appalachian Consumer Rate Relief Funding LLC, a wholly-owned subsidiary of APCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to the under-recovered ENEC deferral balance.
BlueStar	BlueStar Energy Holdings, Inc., a wholly-owned retail electric supplier for customers in Ohio, Illinois and other deregulated electricity markets throughout the United States. BlueStar began doing business as AEP Energy, Inc. in June 2012.
BOA	Bank of America Corporation.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.

Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CRES provider	Competitive Retail Electric Service providers under Ohio law that target retail customers by offering alternative generation service.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CWIP	Construction Work in Progress.

Term	Meaning
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company and consolidated variable interest entity of AEP.
ENEC	Expanded Net Energy Charge.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, a PUCO requirement for electric utilities to adjust their rates by filing with the PUCO.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IEU	Industrial Energy Users-Ohio.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo which defined the sharing of costs and benefits associated with their respective generation plants. This agreement was terminated January 1, 2014.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
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.
KWh	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate transactions among members of the Interconnection Agreement.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.

MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain nonutility subsidiaries.

Term	Meaning
NSR	New Source Review.
OATT	Open Access Transmission Tariff.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Phase-in-Recovery Funding	Ohio Phase-in-Recovery Funding LLC, a wholly-owned subsidiary of OPCo and a consolidated variable interest entity formed for the purpose of issuing and servicing securitization bonds related to phase-in recovery property.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PCA	Power Coordination Agreement among APCo, I&M and KPCo.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generation plant, consisting of two 1,310 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity for AEP and SWEPCo.
SEC	U.S. Securities and Exchange Commission.
SEET	Significantly Excessive Earnings Test.
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.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SSO	Standard service offer.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant, a 534 MW natural gas unit owned by SWEPCo.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring	Legislation enacted in 1999 to restructure the electric utility industry in Texas.

Legislation

TNC	AEP Texas North Company, an AEP electric utility subsidiary.

Term	Meaning
Transition Funding	AEP Texas Central Transition Funding I LLC, AEP Texas Central Transition Funding II LLC and AEP Texas Central Transition Funding III LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant, a 600 MW coal-fired plant in Arkansas that is 73% owned by SWEPCo.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Discussion and Analysis of Financial Condition and Results of Operations," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate, growth or contraction within and changes in market demand and demographic patterns in our service territory.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio.
- Weather conditions, including storms and drought conditions, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generation capacity and the performance of our generation plants.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generation capacity and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation, cost recovery and/or profitability of our generation plants and related assets.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- A reduction in the federal statutory tax rate could result in an accelerated return of deferred federal income taxes to customers.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.

- Our ability to develop and execute a strategy based on a view regarding prices of electricity and other energy-related commodities.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generation units that may be retired before the end of their previously projected useful lives.
- Volatility and changes in markets for capacity and electricity, coal and other energy-related commodities, particularly changes in the price of natural gas.

- Changes in utility regulation and the allocation of costs within regional transmission organizations, including PJM and SPP.
- The transition to market generation in Ohio, including the implementation of ESPs.
- Our ability to successfully and profitably manage our Ohio generation assets in a startup, nonregulated merchant business.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of our debt.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its Registrant Subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information. For a more detailed discussion of these factors, see "Risk Factors" in Part I of this report.

AEP COMMON STOCK AND DIVIDEND INFORMATION

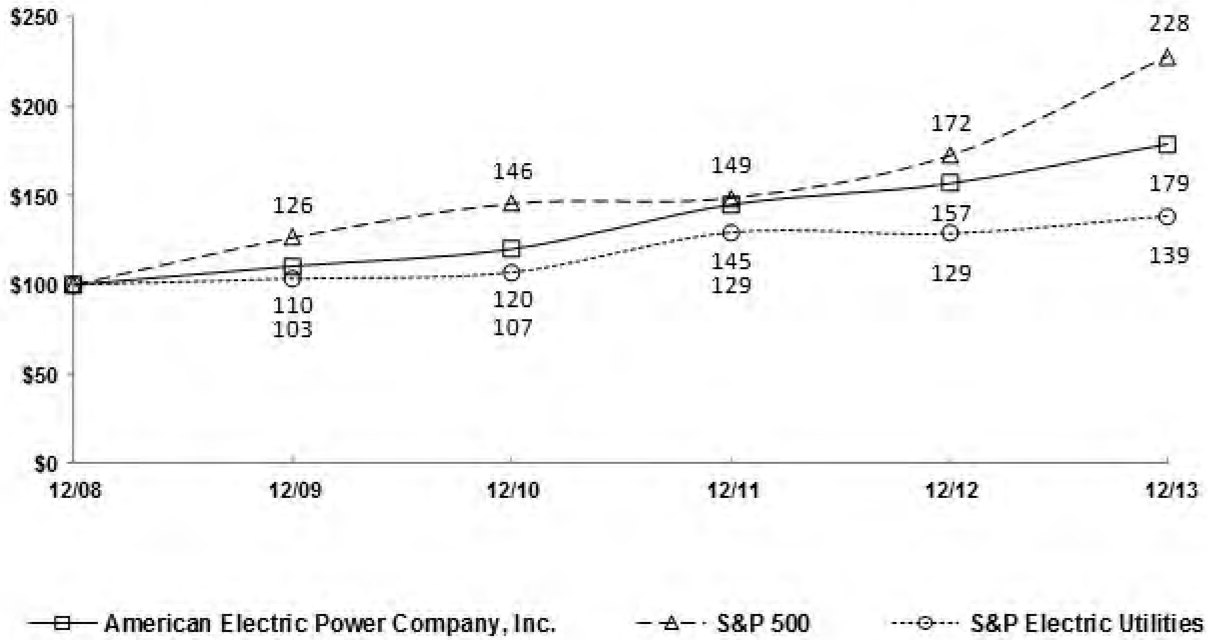
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended	High		Low		Quarter-End Closing Price		Dividend	
December 31, 2013	$	48.40	$	43.01	$	46.74	$	0.50
September 30, 2013		47.59		41.83		43.35		0.49
June 30, 2013		51.60		42.83		44.78		0.49
March 31, 2013		48.68		42.92		48.63		0.47
December 31, 2012	$	45.41	$	40.56	$	42.68	$	0.47
September 30, 2012		44.84		39.62		43.94		0.47
June 30, 2012		40.46		36.97		39.90		0.47
March 31, 2012		41.98		37.46		38.58		0.47

AEP common stock is traded principally on the New York Stock Exchange. As of December 31, 2013, AEP had approximately 78,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., the S&P 500 Index, and the S&P Electric Utilities Index



*$100 invested on 12/31/08 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2013	2012	2011	2010	2009
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 15,357	$ 14,945	$ 15,116	$ 14,427	$ 13,489
Operating Income	$ 2,855	$ 2,656	$ 2,782	$ 2,663	$ 2,771
Income Before Extraordinary Items	$ 1,484	$ 1,262	$ 1,576	$ 1,218	$ 1,370
Extraordinary Items, Net of Tax	-	-	373	-	(5)
Net Income	1,484	1,262	1,949	1,218	1,365
Net Income Attributable to Noncontrolling Interests	4	3	3	4	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,480	1,259	1,946	1,214	1,360
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,480	$ 1,259	$ 1,941	$ 1,211	$ 1,357
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 60,285	$ 57,454	$ 55,670	$ 53,740	$ 51,684
Accumulated Depreciation and Amortization	19,288	18,691	18,699	18,066	17,340
Total Property, Plant and Equipment – Net	$ 40,997	$ 38,763	$ 36,971	$ 35,674	$ 34,344
Total Assets	$ 56,414	$ 54,367	$ 52,223	$ 50,455	$ 48,348
Total AEP Common Shareholders' Equity	$ 16,085	$ 15,237	$ 14,664	$ 13,622	$ 13,140
Noncontrolling Interests	$ 1	$ -	$ 1	$ -	$ -
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ -	$ -	$ -	$ 60	$ 61
Long-term Debt (a)	$ 18,377	$ 17,757	$ 16,516	$ 16,811	$ 17,498
Obligations Under Capital Leases (a)	$ 538	$ 449	$ 458	$ 474 (b)	$ 317
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					

Income Before Extraordinary Items	$ 3.04	$ 2.60	$ 3.25	$ 2.53	$ 2.97
Extraordinary Items, Net of Tax	-	-	0.77	-	(0.01)
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 3.04	$ 2.60	$ 4.02	$ 2.53	$ 2.96
Weighted Average Number of Basic Shares Outstanding (in millions)	487	485	482	479	459
Market Price Range:					
High	$ 51.60	$ 45.41	$ 41.71	$ 37.94	$ 36.51
Low	$ 41.83	$ 36.97	$ 33.09	$ 28.17	$ 24.00
Year-end Market Price	$ 46.74	$ 42.68	$ 41.31	$ 35.98	$ 34.79
Cash Dividends Declared per AEP Common Share	$ 1.95	$ 1.88	$ 1.85	$ 1.71	$ 1.64
Dividend Payout Ratio	64.14%	72.31%	46.02%	67.59%	55.41%
Book Value per AEP Common Share	$ 32.98	$ 31.35	$ 30.36	$ 28.32	$ 27.49

(a) Includes portion due within one year.

(b) Obligations Under Capital Leases increased primarily due to capital leases under new master lease agreements for property that was previously leased under operating leases.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

EXECUTIVE OVERVIEW

Company Overview

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

Our subsidiaries operate an extensive portfolio of assets including:

- Approximately 37,600 megawatts of generating capacity, one of the largest complements of generation in the United States.
- More than 40,000 miles of transmission lines, including 2,110 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern United States.
- Approximately 222,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 5,700 railcars, approximately 3,000 barges, 60 towboats, 25 harbor boats and a coal handling terminal with approximately 18 million tons of annual capacity). Our commercial barging operations annually transport approximately 37 million tons of coal and dry bulk commodities. Approximately 39% of the barging is for transportation of agricultural products, 26% for coal, 20% for steel and 15% for other commodities.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved corporate separation of generation assets and associated liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with Ohio law, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo will purchase power from both affiliated and nonaffiliated entities, subject to PUCO approval, to meet the energy and capacity needs of customers.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value its ownership (867 MW) in Amos Plant, Unit 3 to APCo. The transfer of these generation assets and associated liabilities was approved by the FERC, the Virginia SCC and the WVPSC.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Other Impacts of Corporate Separation

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

Effective January 1, 2014, the FERC approved the following:

- Power Coordination Agreement among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources.
- Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent to address open commitments related to the termination of the Interconnection Agreement and responsibilities to PJM.
- Power Supply Agreement between AGR and OPCo for AGR to supply capacity for OPCo's switched and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through auctions from January 1, 2014 through December 31, 2014.

For a further discussion of corporate separation, see the "Corporate Separation" section of Note 1 and the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters in Note 4.

Ohio Electric Security Plan Filings

2009 – 2011 ESP

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover OPCo's deferred fuel costs in rates beginning September 2012. As of December 31, 2013, OPCo's net deferred fuel balance was $445 million, excluding unrecognized equity carrying costs. Decisions from the Supreme Court of Ohio are pending related to various appeals which, if ordered, could reduce OPCo's net deferred fuel costs balance.

June 2012 – May 2015 Ohio ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015. This ruling was generally upheld in PUCO rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $33/MW day through May 2014 and $148/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is being collected from customers at $3.50/MWh through May 2014 and will be collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR. As of December 31, 2013, OPCo's incurred deferred capacity costs balance was $288 million, including debt carrying costs.

In November 2013, the PUCO issued an order approving OPCo's competitive bid process with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. OPCo must conduct an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In December 2013, the PUCO granted applications for rehearing for further consideration filed by OPCo and intervenors. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012-2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC.

Proposed June 2015 – May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders effective June 2015 through May 2018. This filing is consistent with the PUCO's objective for a full transition from FAC and base generation rates to market. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM and energy auction-based generation through OPCo. Additionally, the application identifies OPCo's intention to submit a separate application to continue the RSR established in the June 2012 – May 2015 ESP in which the unrecovered portion of the deferred capacity costs will continue to be collected at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. Management intends to file this application in the first quarter of 2014.

If OPCo is ultimately not permitted to fully collect its ESP rates including the RSR, and its deferred capacity costs, it could reduce future net income and cash flows and impact financial condition. See "Ohio Electric Security Plan Filing" section of Note 4.

Ohio Customer Choice

In our Ohio service territory, various CRES providers are targeting retail customers by offering alternative generation service. The reduction in gross margin as a result of customer switching in Ohio is partially offset by (a) collection of capacity revenues from CRES providers, (b) off-system sales, (c) deferral of unrecovered capacity costs, (d) RSR collections and (e) revenues from AEP Energy. AEP Energy is our CRES provider and part of our Generation & Marketing segment which targets retail customers, both within and outside of our retail service territory.

Customer Demand

In comparison to 2012, our weather-normalized retail sales decreased 1.6% for the year ended December 31, 2013. Our industrial sales declined 4.5% partially due to lower production levels at Ormet, a large aluminum company. Ormet had a contract to purchase power from OPCo through 2018. In October 2013, Ormet announced that it was unable to emerge from bankruptcy and shut down its operations effective immediately. The loss of Ormet's load will not have a material impact on future gross margin. Power previously sold to Ormet will be available to be sold into wholesale markets.

In 2014, we anticipate weather-normalized retail sales will decline by 1.1%. Excluding Ormet, total weather-normalized retail sales are projected to increase by 0.1% in 2014. The largest decline is projected to occur in the industrial class, principally due to Ormet's decision to shut down. Excluding Ormet, the industrial class is projected to grow by 1.2% in 2014, primarily related to a number of new oil and natural gas expansions, especially around the major shale gas areas within AEP's footprint. Weather-normalized residential sales are projected to decline by 0.9% in 2014, continuing the recent trend of declining use per customer related to higher saturations of energy efficient appliances and the promotion of utility sponsored energy efficiency programs. The commercial class energy sales are projected to remain flat compared to 2013.

PJM Capacity Auction

AGR is required to offer all of its available generation in the PJM Reliability Pricing Model (RPM) auction, which is conducted three years in advance of the actual delivery year. Therefore, the majority of AGR generation assets are subject to PJM capacity prices for periods after May 2015. Through May 2015, AGR will provide generation capacity to OPCo for both switched and non-switched OPCo generation customers. For switched customers, OPCo pays AGR $188.88/MW day. For non-switched OPCo generation customers, OPCo pays AGR for capacity. AGR's non-OPCo load is subject to the PJM RPM auction. Shown below are the current auction prices for capacity, as announced/settled by PJM:

PJM Auction Period	PJM Base Auction Price (per MW day)
June 2013 through May 2014	$ 27.73
June 2014 through May 2015	125.99
June 2015 through May 2016	136.00
June 2016 through May 2017	59.37

We formed a coalition with other utility companies to address mutual concerns related to the PJM capacity auction process, including: (a) import limits for power without firm transmission, (b) placing bidding caps on available demand response resources in comparison to base generation capacity, (c) modification and enforcement of the timing of demand response requirements to better reflect real-time capacity requirements and (d) tightened rules for incremental auctions in which speculative bidders sell resources in the base auction and buy back that capacity in an incremental auction, resulting in no additional capacity and lower market prices. PJM has made three FERC filings related to the first three issues. We anticipate that another filing will be made by PJM later in the first quarter of

2014 to address the fourth issue. In January 2014, FERC accepted without modification PJM's filed recommendations on placing bidding caps on certain demand response products that are available only during the summer period. We expect to receive FERC decisions on the other filings prior to the next RPM auction in May 2014.

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility. As of December 31, 2013, SWEPCo's share of incurred construction expenditures for the Turk Plant was approximately $1.758 billion. As of December 31, 2013, a pretax provision of $59 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total net capitalized expenditures of $1.699 billion.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This Turk Plant output that is currently not subject to cost-based rate recovery and is being sold into the wholesale market. If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant or transmission lines, it could reduce future net income and cash flows and impact financial condition. See the "Turk Plant" section of Note 4.

2012 Texas Base Rate Case

In December 2013, the PUCT issued an order granting rehearing and reversed its decision on consolidated tax savings increasing SWEPCo's annual revenues by $5 million. In January 2014, the PUCT determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result of these rulings, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. These rulings also increased SWEPCo's previously approved annual base rates by a total of $13 million. The resulting annual base rate increase is approximately $52 million. See the "Turk Plant" and the "2012 Texas Base Rate Case" sections of Note 4.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share of the Turk Plant. In February 2013, a settlement was approved by the LPSC that increased Louisiana total rates by approximately $2 million annually, effective March 2013. The March 2013 base rates are based upon a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In May 2013, SWEPCo filed testimony in the prudency review of the Turk Plant. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudency review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition. See the "2012 Louisiana Formula Rate Filing" section of Note 4.

Welsh Plant, Units 1 and 3 - Environmental Projects

To comply with pending Federal EPA regulations, SWEPCo is currently constructing environmental control projects to meet Mercury and Air Toxics Standards for Welsh Plant, Units 1 and 3 at a cost of approximately $410 million, excluding AFUDC. Management currently estimates that the total environmental projects to be completed through 2020 for Welsh Plant, Units 1 and 3 will cost approximately $600 million, excluding AFUDC. As of December 31, 2013, SWEPCo has incurred $32 million in costs related to these projects. SWEPCo will seek recovery of costs it incurs from these projects from its state commissions and FERC customers.

2011 Indiana Base Rate Case

In 2013, the IURC issued an order that granted a $92 million annual increase in base rates based upon a return on common equity of 10.2%. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed an appeal of the orders with the Indiana Court of Appeals. In September 2013, the OUCC filed a brief on appeal that included objections to certain aspects of the rate case. If any part of the IURC order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows. See the "2011 Indiana Base Rate Case" section of Note 4.

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional types of transmission costs that are expected to increase over the next several years.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both units of the Rockport Plant with a dry sorbent injection system. The estimated cost in the application was $285 million, excluding AFUDC to be shared equally between I&M and AEGCo. In November 2013, the IURC approved a settlement agreement that included the approval of the CPCN with an updated estimated CCT Project cost of $258 million, excluding AFUDC, and the recovery of the Indiana jurisdictional share of I&M's ownership share. As of December 31, 2013, we have incurred costs of $109 million related to the CCT Project, including AFUDC. See the "Rockport Plant Clean Coal Technology Project (CCT Project)" section of Note 4.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of December 31, 2013, I&M has incurred costs of $380 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In October 2013, I&M filed an application with the IURC for LCM rider rates effective January 2014. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON.

If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition. See "Cook Plant Life Cycle Management Project (LCM Project)" section of Note 4.

Repositioning Efforts

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that resulted in sustainable cost savings. This process included evaluations of our employee and retiree benefit programs as well as evaluations of the functional effectiveness and staffing levels of our finance and accounting, information technology, generation and supply chain and procurement organizations. While we have completed certain aspects of this program, our continuous improvement initiatives in generation, distribution, transmission, supply chain, procurement and the corporate center continues to yield cost savings for many of our subsidiaries, allowing us to direct many of these savings into infrastructure and other areas of our business.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to reduce future net income and cash flows and impact financial condition.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants' actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court has granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. Our motion to dismiss the case, filed in October 2013, is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with environmental control requirements. We will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. We are also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. We believe that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. Environmental rules could result in accelerated depreciation, impairment of assets or regulatory disallowances. If we are unable to recover the costs of environmental compliance, it would reduce future net income and cash flows and impact financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2013, the AEP System had a total generating capacity of nearly 37,600 MWs, of which over 23,700 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon our estimates, investment to meet these proposed requirements ranges from approximately $3 billion to $3.5 billion between 2013 and 2020. These amounts include investments to convert some of our coal generation to natural gas. If natural gas conversion is not completed, these units could be retired sooner than planned.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors. In addition, we are continuing to evaluate the economic feasibility of environmental investments on nonregulated plants.

Subject to the factors listed above and based upon our continuing evaluation, we intend to retire the following plants or units of plants before or during 2016:

Company	**Plant Name and Unit**	**Generating Capacity (in MWs)**
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/AGR	Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-4	995
KPCo	Big Sandy Plant, Unit 2	800
AGR	Kammer Plant	630
AGR	Muskingum River Plant, Units 1-5	1,440
AGR	Picway Plant	100
PSO	Northeastern Station, Unit 4	470
SWEPCo	Welsh Plant, Unit 2	528
Total		6,533

As of December 31, 2013, the net book value of the AGR units listed above was zero. The net book value, before cost of removal, including related material and supplies inventory and CWIP balances of the other plants in the table above was $1 billion. See Note 5 for further discussion.

In 2013, we re-evaluated potential courses of action with respect to the planned operation of Muskingum River Plant, Unit 5 and concluded that completion of a refueling project which would extend the unit's useful life is remote. As a result, in 2013, we completed an impairment analysis and recorded a $154 million pretax ($99 million, net of tax) impairment charge for AGR's net book value of Muskingum River Plant, Unit 5. We expect to retire the plant no later than 2015. See "Muskingum River Plant, Unit 5" section of Note 7.

In addition, we are in the process of obtaining permits and other necessary regulatory approvals for either the conversion of some of our coal units to natural gas or installing emission control equipment on certain units. The following table lists the plants or units that are either awaiting regulatory approval or are still being evaluated by management based on changes in emission requirements and demand for power:

Company	Plant Name and Unit	Generating Capacity (in MWs)
KPCo	Big Sandy Plant, Unit 1	278
PSO	Northeastern Station, Unit 3	470
Total		748

As of December 31, 2013, the net book value before cost of removal, including related material and supplies inventory and CWIP balances, of the plants in the table above was $295 million.

Volatility in natural gas prices, pending environmental rules and other market factors could also have an adverse impact on the accounting evaluation of the recoverability of the net book values of coal-fired units. For regulated plants that we may close early, we are seeking regulatory recovery of remaining net book values. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows.

Modification of the NSR Litigation Consent Decree

In 2007, the U.S. District Court for the Southern District of Ohio approved a consent decree between the AEP subsidiaries in the eastern area of the AEP System and the Department of Justice, the Federal EPA, eight northeastern states and other interested parties to settle claims that the AEP subsidiaries violated the NSR provisions of the CAA when it undertook various equipment repair and replacement projects over a period of nearly 20 years. The consent decree's terms include installation of environmental control equipment on certain generating units, a declining cap on SO_2 and NO_x emissions from the AEP System and various mitigation projects.

The original consent decree required certain types of control equipment to be installed at Muskingum River Plant, Unit 5, Big Sandy Plant, Unit 2 and the two units of the Rockport Plant in 2015, 2017 and 2019, respectively. In January 2013, an agreement to modify the consent decree was reached and filed with the court. The terms of the agreement include more options for the affected units (including alternative control technologies, re-fueling and/or retirement), more stringent SO_2 emission caps for the AEP System and additional mitigation measures. The modified consent decree was approved by the court in May 2013. For the units of the Rockport Plant, the modified decree requires installation of dry sorbent injection technology for SO_2 control on both units in 2015. In addition, the consent decree imposes a declining plant-wide cap on SO_2 emissions beginning in 2016.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES), Unit 4 in 2016 and additional environmental controls on NES, Unit 3 to continue operations through 2026. As of December 31, 2013, the net book values of NES, Units 3 and 4 were $208 million and $106 million, respectively, before cost of removal, including materials and supplies inventory and CWIP. In August 2013, the OCC dismissed PSO's environmental compliance plan case without prejudice but will permit PSO to seek recovery in a future proceeding. PSO will address the environmental compliance plan issues in future regulatory proceedings when it seeks cost recovery of the plan. If PSO is ultimately not permitted to fully recover its net book value of NES, Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the District of Columbia Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR was challenged in the courts. The U.S. Court of Appeals for the District of Columbia Circuit issued an order in December 2011 staying the effective date of the rule pending judicial review. In 2012, a panel of the U.S. Court of Appeals for the District of Columbia Circuit issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing CAIR until a replacement rule is finalized. That decision has been appealed to the U.S. Supreme Court. Nearly all of the states in which our power plants are located are covered by CAIR.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants (discussed in detail below) in 2012.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas. The Arkansas SIP was disapproved and the state is developing a revised submittal. In June 2012, the Federal EPA published revisions to the regional haze rules to allow states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_x emissions based on its determination that CSAPR results in greater visibility improvements than source-specific BART in the CSAPR states. This rule is being challenged in the U.S. Court of Appeals for the District of Columbia Circuit and its fate is uncertain given developments in the CSAPR litigation.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA has proposed to include CO_2 emissions in standards that apply to new electric utility units and will consider whether such standards are appropriate for other source categories in the future.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for PM, SO_2, NO_x and lead, and is currently reviewing the NAAQS for ozone. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting our operations are discussed in the following sections.

Cross-State Air Pollution Rule (CSAPR)

In 2011, the Federal EPA issued CSAPR. Certain revisions to the rule were finalized in 2012. CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis. Arkansas and Louisiana are subject only to the seasonal NO_x program in the rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia were reduced significantly in the rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011 with an increased NO_x emission budget for the 2012 compliance year. The Federal EPA issued a final Error Corrections Rule and further CSAPR revisions in 2012 to make corrections to state budgets and unit allocations and to remove the restrictions on interstate trading in the first phase of CSAPR.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the U.S. Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In 2011, the court granted the motions for stay. In 2012, the panel issued a decision vacating and remanding CSAPR to the Federal EPA with instructions to continue implementing the Clean Air Interstate Rule until a replacement rule is finalized. The majority determined that the CAA does not allow the Federal EPA to "overcontrol" emissions in an upwind state and that the Federal EPA exceeded its statutory authority by failing to allow states an opportunity to develop their own implementation plans before issuing a FIP. The Federal EPA and other respondents filed petitions for rehearing but in January 2013, the U.S. Court of Appeals for the District of Columbia Circuit denied all petitions for rehearing. The petition for further review filed by the Federal EPA and other parties in the U.S. Supreme Court was granted in June 2013. Separate appeals of the supplemental rule, the Error Corrections Rule and the further revisions have been filed, but are being held in abeyance.

The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers. We cannot predict the outcome of the pending litigation.

Mercury and Other Hazardous Air Pollutants Regulation

In 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule was April 16, 2012 and compliance is required within three years. We are participating through various organizations in the petitions for administrative reconsideration and judicial review that have been filed. In 2012, the Federal EPA published a notice announcing that it would accept comments on its reconsideration of certain issues related to the new source standards, including clarification of the requirements that apply during periods of start-up and shut down, measurement issues and the application of variability factors that may have an impact on the level of the standards. The Federal EPA issued revisions to the new source standards consistent with the proposed rule, except the start-up and shut down provisions in March 2013. The Federal EPA is still considering additional changes to the start-up and shut down provisions.

The final rule contains a slightly less stringent PM limit for existing sources than the original proposal and allows operators to exclude periods of start-up and shut down from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines. We are participating in petitions for review filed in the U.S. Court of Appeals for the District of Columbia Circuit by several organizations of which we are members. Certain issues related to the standards for new coal-fired units have been severed from the main case and are being held in abeyance pending completion of the Federal EPA's reconsideration proceeding. The case is briefed and argued, and remains pending before the court.

Regional Haze

In 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA proposed to approve all of the NO_x control measures in the SIP and disapprove the SO_2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA finalized a FIP that would require these units to install technology capable of reducing SO_2 emissions to 0.06 pounds per million British thermal units within five years of the effective date of the FIP. PSO filed a petition for review of the FIP in the Tenth Circuit Court of Appeals and engaged in settlement discussions with the Federal EPA, the State of Oklahoma and other parties. In November 2012, we notified the court that the parties had reached agreement on a settlement that would provide for submission of a revised Regional Haze SIP requiring the retirement of one coal-fired unit of PSO's Northeastern Station no later than 2016, installation of emission controls on the second coal-fired Northeastern unit in 2016 and retirement of the second unit no later than 2026. The Tenth Circuit Court of Appeals is holding the appeal in abeyance pending implementation of the settlement. A revised regional haze SIP was adopted by the State of Oklahoma and the Federal EPA approved the revised SIP in February 2014. Upon publication of the final approval and withdrawal of the FIP, the Tenth Circuit proceeding will be dismissed.

CO_2 Regulation

In March 2012, the Federal EPA issued a proposal to regulate CO_2 emissions from new fossil fuel-fired electricity generating units. The proposed rule establishes a new source performance standard of 1,000 pounds of CO_2 per megawatt hour of electricity generated, a rate that most natural gas combined cycle units can meet, but that is substantially below the emission rate of a new pulverized coal generator or an integrated gas combined cycle unit that uses coal for fuel. As proposed, the rule does not apply to new gas-fired stationary combustion turbines used as peaking units, does not apply to existing, modified or reconstructed sources and does not apply to units whose CO_2 emission rate increases as a result of the addition of pollution control equipment to control criteria pollutant emissions or HAPs. The rule is not anticipated to have a significant immediate impact on the AEP System since it does not apply to existing units or units that have already commenced construction. New source performance standards affect units that have not yet received permits. The proposed standards were challenged in the U.S. Court of Appeals for the District of Columbia Circuit. That case was dismissed because the court determined that no final agency action had yet been taken.

In June 2013, President Obama issued a memorandum to the Administrator of the Federal EPA directing the agency to develop and issue a new proposal regulating carbon emissions from new electric generating units in September 2013. The new proposal was issued in September 2013 and requires new large natural gas units to meet 1,000 pounds of CO_2 per MWh of electricity generated and small natural gas units to meet 1,100 pounds of CO_2 per MWh. New coal-fired units are required to meet the 1,100 pounds of CO_2 per MWh limit, with the option to meet the tighter limits if they choose to average emissions over multiple years. This proposal was published in the Federal Register in January 2014 and the March 2012 proposal has been withdrawn.

The Federal EPA was also directed to develop and issue a separate proposal regulating carbon emissions from existing, modified and reconstructed electric generating units before June 2014, to finalize those standards by June 2015 and to require states to submit revisions to their implementation plans including such standards no later than June 2016. The President directed the Federal EPA, in developing this proposal, to directly engage states, leaders in the power sector, labor leaders and other stakeholders, to tailor the regulations to reduce costs, to develop market-based instruments and allow regulatory flexibilities and "assure that the standards are developed and implemented in a manner consistent with the continued provision of reliable and affordable electric power." We cannot currently predict the impact these programs may have on future resource plans or our existing generating fleet, but the costs may be substantial.

In June 2012, the U.S. Court of Appeals for the District of Columbia Circuit issued a decision upholding, in all material respects, the Federal EPA's endangerment finding, its regulatory program for CO_2 emissions from new motor vehicles and its plan to phase in regulation of CO_2 emissions from stationary sources under the Prevention of Significant Deterioration (PSD) and Title V operating permit programs. A petition for rehearing was filed which the court denied in December 2012. The U.S. Supreme Court granted several petitions for review and will determine whether the Federal EPA made a reasonable determination that adoption of the motor vehicle standards trigger PSD and Title V permitting obligations for stationary sources. A decision is expected by June 2014.

The Federal EPA also finalized a rule in June 2012 that retains the current thresholds for permitting stationary sources under the PSD and Title V operating permit programs at 100,000 tons per year for new sources and 75,000 tons per year for modified sources. The Federal EPA also confirmed that it will re-evaluate these thresholds during its five-year review in 2016. Our generating units are large sources of CO_2 emissions and we will continue to evaluate the permitting obligations in light of these thresholds.

Coal Combustion Residual Rule

In 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment. In 2013, the Federal EPA also issued a notice of data availability requesting comments on a narrow set of items.

Various environmental organizations and industry groups filed a petition seeking to establish deadlines for a final rule. The Federal EPA opposed the petition and sought additional time to coordinate the issuance of a final rule with the issuance of new effluent limitations under the Clean Water Act for utility facilities. In October 2013, the U.S. District Court for the District of Columbia issued a final order partially ruling in favor of the Federal EPA for dismissal of two counts, ruling in favor of the environmental organizations on one count and directing the Federal EPA to provide the court with a proposed schedule for completion of the rulemaking. In January 2014, the parties filed a motion with the court to establish December 2014 as the Federal EPA's deadline for publication of the rule. The court will establish a deadline for the final rule following a comment period for interested parties.

In February 2014, the Federal EPA completed an evaluation of the beneficial uses of coal fly ash in concrete and wallboard and concluded that the Federal EPA supports these beneficial uses. Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. In June 2012, the Federal EPA issued additional Notices of Data Availability and requested public comments. We submitted comments in July 2012. Issuance of a final rule is expected in 2014. We are preparing to begin activities to implement the rule following its issuance and an analysis of the final requirements.

In addition, the Federal EPA issued an information collection request and is developing revised effluent limitation guidelines for electricity generating facilities. A proposed rule was signed in April 2013 with a final rule expected in 2014. The Federal EPA proposed eight options of increasing stringency and cost for fly ash and bottom ash transport water, scrubber wastewater, leachate from coal combustion byproduct landfills and impoundments and other wastewaters associated with coal-fired generating units, with four labeled preferred options. Certain of the Federal EPA's preferred options have already been implemented or are part of our long-term plans. We continue to review the proposal in detail to evaluate whether our plants are currently meeting the proposed limitations, what technologies have been incorporated into our long-range plans and what additional costs might be incurred if the Federal EPA's most stringent options were adopted. We submitted detailed comments to the Federal EPA in September 2013 and participated in comments filed by various organizations of which we are members.

Climate Change

National public policy makers and regulators in the 11 states we serve have diverse views on climate change. We are currently focused on responding to these emerging views with prudent actions, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA.

Several states have adopted programs that directly regulate CO_2 emissions from power plants. The majority of the states where we have generating facilities have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We estimate that our 2013 emissions were approximately 115 million metric tons. This represents a reduction of 21% compared to our 2005 CO_2 emissions of approximately 145 million metric tons.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 could result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. Public perception may ultimately have a significant impact on future legislation and regulation that could adversely affect our ability to recover our investments in coal-fired plants.

Climate change and its resultant impact on weather patterns could modify our customers' power usage. Our customers' energy needs currently vary with weather conditions and the economy. Increased or decreased energy usage could require the acquisition or construction of more generation and transmission assets or cause early retirement of such assets. The timing and duration of extreme weather conditions may require more system backup and contribute to increased system stresses, including service interruptions and increased storm restoration costs. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales and higher margins.

To the extent climate change affects a region's economic health, it could also affect our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Vertically Integrated Utilities segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

During the fourth quarter of 2013, we realigned our business segments as a result of corporate separation and plant transfers. We retrospectively adjusted 2012 and 2011 segment information to reflect our new business segments. See the "Corporate Separation" section of Executive Overview.

Our reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve remaining generation service customers.

Generation & Marketing

- Nonregulated generation in ERCOT and PJM.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission only subsidiaries and transmission only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

AEP River Operations

- Commercial barging operations that transports liquids, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

The table below presents Income Before Extraordinary Item by segment for the years ended December 31, 2013, 2012 and 2011.

	Years Ended December 31,		
	2013	2012	2011
		(in millions)	
Vertically Integrated Utilities	$ 681	$ 803	$ 710

Transmission and Distribution Utilities	358	389	404
Generation & Marketing	228	100	439
AEP Transmission Holdco	80	43	30
AEP River Operations	12	15	45
Corporate and Other (a)	125	(88)	(52)
Income Before Extraordinary Item	$ 1,484	$ 1,262	$ 1,576

(a) While not considered a reportable segment, Corporate and Other primarily includes management and professional services to AEP provided at cost to AEP subsidiaries and the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

AEP CONSOLIDATED

2013 Compared to 2012

Income Before Extraordinary Item increased from $1,262 million in 2012 to $1,484 million in 2013 primarily due to:

- Successful rate proceedings in our various jurisdictions.
- 2012 impairments of certain Ohio generation plants.
- A decrease in Ohio depreciation expense due to impairments of certain Ohio generation plants.
- A favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013.

These increases were partially offset by:

- Impairments during 2013 for the following:
  - Muskingum River Plant, Unit 5.
  - A write-off from a disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order.
  - A decision from the KPSC disallowing scrubber costs on KPCo's Big Sandy Plant.
- The loss of retail generation customers in Ohio to various CRES providers.
- 2012 reversal of a 2011 recorded obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.

2012 Compared to 2011

Income Before Extraordinary Item decreased from $1,576 million in 2011 to $1,262 million in 2012 primarily due to:

- A decrease in carrying costs income due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- 2012 impairments of certain Ohio generation plants.
- The loss of retail generation customers in Ohio to various CRES providers.
- A decrease in weather-related usage.
- The elimination of POLR charges, effective June 2011, partially offset by the 2011 provision for refund of POLR charges. The refund provision was recorded as a result of the October 2011 PUCO remand order.
- Expenses associated with the early retirement of Parent debt in 2012.
- Expenses related to the 2012 sustainable cost reductions.
- The 2012 adjustment of a U.K. Windfall Tax provision as a result of a related Supreme Court case.

These decreases were partially offset by:

- Successful rate proceedings in our various jurisdictions.
- Lower spending in 2012 as a result of our cost containment efforts.
- A 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of OPCo's modified stipulation.

- The 2011 plant impairments for Sporn Plant, Unit 5 and for the FGD project at Muskingum River Plant, Unit 5.
- The 2011 write-off related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of the November 2011 Texas Court of Appeals decision.
- A loss incurred in 2011 related to a settlement of litigation with BOA and Enron.

Our results of operations are discussed below by operating segment.

VERTICALLY INTEGRATED UTILITIES

Vertically Integrated Utilities	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 9,992	$ 9,418	$ 9,702
Fuel and Purchased Electricity	4,770	4,408	4,870
Gross Margin	5,222	5,010	4,832
Other Operation and Maintenance	2,276	2,219	2,237
Asset Impairments and Other Related Charges	72	13	49
Depreciation and Amortization	941	873	785
Taxes Other Than Income Taxes	372	344	339
Operating Income	1,561	1,561	1,422
Interest and Investment Income	7	5	13
Carrying Costs Income	14	28	17
Allowance for Equity Funds Used During Construction	35	72	82
Interest Expense	(540)	(520)	(514)
Income Before Income Tax Expense and Equity Earnings	1,077	1,146	1,020
Income Tax Expense	398	345	312
Equity Earnings of Unconsolidated Subsidiaries	2	2	2
Income Before Extraordinary Item	$ 681	$ 803	$ 710

Summary of KWh Energy Sales for Vertically Integrated Utilities

	Years Ended December 31, 2013	2012	2011
	(in millions of KWhs)		
Retail:			
Residential	33,851	33,199	35,135
Commercial	25,037	25,278	25,651
Industrial	34,216	34,692	34,333
Miscellaneous	2,284	2,356	2,349
Total Retail	95,388	95,525	97,468
Wholesale	31,919	28,671	28,290
Total KWhs	127,307	124,196	125,758

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Vertically Integrated Utilities

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in degree days)	
Eastern Region			
Actual - Heating (a)	2,949	2,216	2,566
Normal - Heating (b)	2,734	2,774	2,772
Actual - Cooling (c)	1,040	1,253	1,280
Normal - Cooling (b)	1,080	1,079	1,066
Western Region			
Actual - Heating (a)	1,772	1,070	1,582
Normal - Heating (b)	1,501	1,537	1,534
Actual - Cooling (c)	2,163	2,635	2,830
Normal - Cooling (b)	2,202	2,186	2,165

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region and Western Region cooling degree days are calculated on a 65 degree temperature base.

2013 Compared to 2012

**Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Vertically Integrated Utilities Before Extraordinary Item
(in millions)**

Year Ended December 31, 2012	$ 803
Changes in Gross Margin:	
Retail Margins	196
Off-system Sales	(26)
Transmission Revenues	41
Other Revenues	1
Total Change in Gross Margin	212
Changes in Expenses and Other:	
Other Operation and Maintenance	(57)
Asset Impairments and Other Related Charges	(59)
Depreciation and Amortization	(68)
Taxes Other Than Income Taxes	(28)
Interest and Investment Income	2
Carrying Costs Income	(14)
Allowance for Equity Funds Used During Construction	(37)
Interest Expense	(20)
Total Change in Expenses and Other	(281)
Income Tax Expense	(53)
Year Ended December 31, 2013	$ 681

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $196 million primarily due to the following:
  - Successful rate proceedings in our service territories, which include:
    - A $153 million rate increase for SWEPCo.
    - A $112 million rate increase for I&M.
    - A $9 million rate increase for APCo.

      For the rate increases described above, $42 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $29 million increase in weather-related usage in our eastern and western regions primarily due to increases of 33% and 66%, respectively, in heating degree days partially offset by decreases in our eastern and western regions of 17% and 18%, respectively, in cooling degree days.

  These increases were partially offset by:
  - A $15 million decrease in SWEPCo's municipal and cooperative revenues primarily due to lower realizations from changes in sales volume mix.
  - A $23 million decrease due to lower weather normalized retail sales.
  - A $12 million increase in other variable electric generation expenses.

  - A $9 million deferral of APCo's additional wind purchase costs in 2012 as a result of the June 2012 Virginia SCC fuel factor order.
  - A $9 million decrease due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.
- **Margins from Off-system Sales** decreased $26 million primarily due to lower PJM capacity revenue, reduced trading and marketing margins, partially offset by higher prices and volumes.
- **Transmission Revenues** increased $41 million primarily due to increased investment in the PJM and SPP regions. These increased revenues are offset-in-part in Other Operation and Maintenance expenses below.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $57 million primarily due to the following:
  - A $33 million increase in recoverable PJM and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers.
  - A $30 million write-off in 2013 of previously deferred 2012 Virginia storm costs resulting from the 2013 enactment of a Virginia law.
  - A $22 million increase in storm-related expenses primarily in APCo's service territory.
  - A $21 million increase in plant outage expenses.

  These increases were partially offset by:
  - A $26 million decrease due to expenses related to the 2012 sustainable cost reductions.
  - A $25 million decrease due to an agreement reached to settle an insurance claim in 2013.
- **Asset Impairments and Other Related Charges** increased $59 million primarily due to the following:
  - A $39 million increase due to APCo's 2013 write-off from a regulatory disallowance of a portion of Amos Plant, Unit 3 pursuant to a Virginia SCC order approving the transfer of Amos Plant, Unit 3.
  - A $33 million increase due to KPCo's 2013 write-off of scrubber costs on the Big Sandy Plant and other generation costs in accordance with a KPSC's October 2013 order.

  These increases were partially offset by:
  - A 2012 write-off of an additional $13 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap.
- **Depreciation and Amortization** expenses increased $68 million primarily due to the following:
  - A $40 million increase due to the Turk Plant being placed in service in December 2012.
  - A $26 million increase due to higher depreciable base and higher depreciation rates reflecting a change in Tanners Creek Plant's estimated life approved by the MPSC effective April 2012 and by the IURC effective March 2013. The majority of the increase in depreciation for Tanners Creek Plant's life is offset within Gross Margin.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $13 million decrease in amortization as a result of the cessation of the Virginia Environmental and Reliability surcharge and the Virginia Environmental Rate Adjustment Clause in January 2013 and March 2013, respectively.
- **Taxes Other Than Income Taxes** increased $28 million primarily due to increased property taxes as a result of increased capital investments.
- **Carrying Costs Income** decreased $14 million primarily due to an increased recovery of Virginia environmental costs in new base rates as approved by the Virginia SCC in late January 2012 and decreased carrying charges related to the Dresden Plant.
- **Allowance for Equity Funds Used During Construction** decreased $37 million primarily due to completed construction of the Turk Plant in December 2012.
- **Interest Expense** increased $20 million primarily due to a decrease in the debt component of AFUDC due to completed construction of the Turk Plant in December 2012 partially offset by lower average outstanding long-term debt balances and an increase in the debt component of AFUDC related to projects at the Cook Plant.
- **Income Tax Expense** increased $53 million primarily due to the recording of federal and state income tax adjustments and other book/tax differences which are accounted for on a flow-through basis, offset-in-part by a decrease in pretax book income.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Vertically Integrated Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$	710
Changes in Gross Margin:		
Retail Margins		181
Off-system Sales		(13)
Transmission Revenues		19
Other Revenues		(9)
Total Change in Gross Margin		178
Changes in Expenses and Other:		
Other Operation and Maintenance		18
Asset Impairments and Other Related Charges		36
Depreciation and Amortization		(88)
Taxes Other Than Income Taxes		(5)
Interest and Investment Income		(8)
Carrying Costs Income		11
Allowance for Equity Funds Used During Construction		(10)
Interest Expense		(6)
Total Change in Expenses and Other		(52)
Income Tax Expense		(33)
Year Ended December 31, 2012	$	803

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased electricity were as follows:

- **Retail Margins** increased $181 million primarily due to the following:
  - A $130 million increase due to lower capacity settlement expenses under the Interconnection Agreement, net of recovery in West Virginia and environmental deferrals in Virginia. This increase was primarily a result of a mild winter in 2012 and its impact on APCo's winter peak, APCo's completion of the Dresden Plant in January 2012 and the removal of Sport Plant, Unit 5 from the Interconnection Agreement in September 2011.
  - Successful rate proceedings in our service territories which include:
    - An $87 million rate increase for APCo.
    - A $17 million rate increase for I&M.
    - A $13 million rate increase for PSO.
    - An $11 million rate increase for WPCo.

      For the rate increases described above, $99 million relates to riders/trackers which have corresponding increases in other expense items below.
  - A $24 million write-off in 2011 related to APCo's disallowance of certain Virginia environmental costs

incurred in 2009 and 2010 as a result of a November 2011 Virginia SCC order.

- A $9 million deferral of APCo's additional wind purchase costs in 2012 as a result of a June 2012 Virginia SCC fuel factor order.
- A $9 million increase due to adjustments for previously disallowed environmental costs by the November 2011 Virginia SCC order subsequently determined in 2012 to be appropriate for recovery by the Supreme Court of Virginia.

These increases were partially offset by:

- A $71 million decrease in weather-related usage in our eastern and western regions primarily due to decreases of 14% and 32%, respectively, in heating degree days and a 7% decrease in cooling degree days in our western region.

- **Margins from Off-system Sales** decreased $13 million primarily due to lower PJM capacity revenue, reduced trading and marketing margins and lower power prices.
- **Transmission Revenues** increased $19 million primarily due to increased investment in the PJM region. These increased revenues are offset-in-part in Other Operation and Maintenance expenses below.
- **Other Revenues** decreased $9 million primarily due to a decrease in miscellaneous sales partially offset by a 2011 unfavorable provision for refund of outage insurance proceeds.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $18 million primarily due to the following:
  - A $46 million decrease in plant outage and other plant operating and maintenance expenses.
  - A $41 million decrease due to the 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $13 million decrease due to APCo's deferral of transmission costs for the Virginia Transmission Rate Adjustment Clause as allowed by the Virginia SCC recovered dollar-for-dollar within Gross Margin.

  These decreases were partially offset by:
  - A $33 million increase due to the 2011 deferral of 2009 storm costs and the 2010 cost reduction initiatives as allowed by the WVPSC.
  - A $27 million increase due to the favorable 2011 asset retirement obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - A $26 million increase due to expenses related to the 2012 sustainable cost reductions.
- **Asset Impairments and Other Related Charges** decreased $36 million due to the 2011 write-off of $49 million related to SWEPCo's expected Texas jurisdictional portion of the Turk Plant in excess of the Texas capital cost cap as a result of a November 2011 Texas Court of Appeals decision. This was partially offset by the 2012 write-off of an additional $13 million related to SWEPCo's Texas capital cost cap.
- **Depreciation and Amortization** expenses increased $88 million primarily due to the following:
  - A $48 million combined increase in depreciation for APCo and I&M primarily due to increases in depreciation rates effective February 2012 (Virginia) and April 2012 (Michigan), respectively. The majority of this increase in depreciation is offset within Gross Margin.
  - An $18 million increase in amortization primarily as a result of the Virginia Environmental Rate Adjustment Clause and the Virginia E&R surcharge, both effective February 2012. This increase in amortization is offset within Gross Margin.
  - Overall higher depreciable property balances.
- **Carrying Costs Income** increased $11 million due to adjustments for disallowed environmental costs as approved in a November 2011 Virginia SCC order and 2012 adjustments for certain costs subsequently determined by the Supreme Court of Virginia to be appropriate for recovery.
- **Allowance for Equity Funds Used During Construction** decreased $10 million primarily due to the completion of APCo's Dresden Plant in January 2012 and I&M's nuclear fuel preparation for usage, partially offset by increases related to SWEPCo's construction of the Turk Plant.
- **Income Tax Expense** increased $33 million primarily due to an increase in pretax book income offset-in-part by the recording of federal and state income tax adjustments.

TRANSMISSION AND DISTRIBUTION UTILITIES

Transmission and Distribution Utilities	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 4,478	$ 4,819	$ 5,156
Purchased Electricity	1,627	2,072	2,711
Gross Margin	2,851	2,747	2,445
Other Operation and Maintenance	1,003	911	954
Depreciation and Amortization	591	561	549
Taxes Other Than Income Taxes	435	428	417
Operating Income	822	847	525
Interest and Investment Income	2	4	7
Carrying Costs Income	16	24	375
Allowance for Equity Funds Used During Construction	8	6	9
Interest Expense	(292)	(291)	(293)
Income Before Income Tax Expense	556	590	623
Income Tax Expense	198	201	219
Income Before Extraordinary Item	$ 358	$ 389	$ 404

Summary of KWh Energy Sales for Transmission and Distribution Utilities

	Years Ended December 31, 2013	2012	2011
	(in millions of KWhs)		
Retail:			
Residential	25,531	25,581	26,520
Commercial	24,631	24,746	25,116
Industrial	22,668	24,902	25,334
Miscellaneous	710	716	751
Total Retail (a)	73,540	75,945	77,721
Wholesale	8	8	8
Total KWhs	73,548	75,953	77,729

(a) Represents energy delivered to distribution customers.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Transmission and Distribution Utilities

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in degree days)	
Eastern Region			
Actual - Heating (a)	3,383	2,610	3,107
Normal - Heating (b)	3,229	3,276	3,266
Actual - Cooling (c)	1,029	1,248	1,112
Normal - Cooling (b)	954	948	936
Western Region			
Actual - Heating (a)	368	177	394
Normal - Heating (b)	337	352	351
Actual - Cooling (d)	2,737	3,100	3,242
Normal - Cooling (b)	2,608	2,584	2,557

(a) Heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 70 degree temperature base.

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Transmission and Distribution Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2012	$	389
Changes in Gross Margin:		
Retail Margins		55
Off-System Sales		1
Transmission Revenues		46
Other Revenues		2
Total Change in Gross Margin		104
Changes in Expenses and Other:		
Other Operation and Maintenance		(92)
Depreciation and Amortization		(30)
Taxes Other Than Income Taxes		(7)
Interest and Investment Income		(2)
Carrying Costs Income		(8)
Allowance for Equity Funds Used During Construction		2
Interest Expense		(1)
Total Change in Expenses and Other		(138)
Income Tax Expense		3
Year Ended December 31, 2013	$	358

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity were as follows:

- **Retail Margins** increased $55 million primarily due to the following:
  - A $123 million increase in revenues associated with OPCo's Universal Service Fund (USF) surcharge and Distribution Investment Recovery Rider. A portion of these increases have corresponding increases in other expense items below.
  - A $17 million increase related to favorable regulatory proceedings for OPCo.

  These increases were partially offset by:
  - A $40 million decrease related to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
  - A $35 million decrease due to OPCo's partial reversal in 2012 of a 2011 fuel provision related to CRES providers.
- **Transmission Revenues** increased $46 million primarily due to increased transmission revenues from Ohio customers who switched to alternative CRES providers.

Expenses and Other and Income Tax Expense changed between years as follows:

Other Operation and Maintenance expenses increased $92 million primarily due to the following:

-
    - An $86 million increase in remitted USF surcharge payments to the Ohio Department of Development to fund an energy assistance program for qualified Ohio customers. This increase was offset by a corresponding increase in retail margins above.
    - A $30 million net increase related to the reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation and the PUCO's August 2012 approval of the June 2012-May 2015 ESP.

These increases were partially offset by:

- A $14 million decrease in expenses related to the 2012 sustainable cost reductions.
- A $13 million decrease in Ohio's *gridSMART*® expenses primarily due to a reduction in the operation

and maintenance component of the *gridSMART®* rider for prior years' over collections. This decrease was partially offset by a corresponding increase in Depreciation and Amortization.

- **Depreciation and Amortization** expenses increased $30 million primarily due to the following:
  - An $8 million increase due to OPCo's and TCC's issuance of securitization bonds in August 2013 and March 2012, respectively. This increase in OPCo's and TCC's securitization related amortizations are offset within Gross Margin.
  - A $7 million increase due to increased investment in distribution and transmission plant.
  - A $4 million increase in Ohio's *gridSMART®* expenses primarily due to an increase in the depreciation component of the *gridSMART®* rider to recover prior years' under collections. This increase was offset by a corresponding decrease in operation and maintenance expense above.
- **Taxes Other Than Income Taxes** increased $7 million primarily due to increased property taxes.
- **Carrying Costs Income** decreased $8 million primarily due to the first quarter 2012 recording of debt carrying costs prior to TCC's issuance of securitization bonds in March 2012.
- **Income Tax Expense** decreased $3 million primarily due to a decrease in pretax book income offset-in-part by the recording of state income tax adjustments.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Transmission and Distribution Utilities Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$ 404
Changes in Gross Margin:	
Retail Margins	192
Transmission Revenues	59
Other Revenues	51
Total Change in Gross Margin	302
Changes in Expenses and Other:	
Other Operation and Maintenance	43
Depreciation and Amortization	(12)
Taxes Other Than Income Taxes	(11)
Interest and Investment Income	(3)
Carrying Costs Income	(351)
Allowance for Equity Funds Used During Construction	(3)
Interest Expense	2
Total Change in Expenses and Other	(335)
Income Tax Expense	18
Year Ended December 31, 2012	$ 389

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of purchased electricity were as follows:

- **Retail Margins** increased $192 million primarily due to the following:
  - A $156 million increase in revenues primarily associated with OPCo's Retail Stability Rider, Deferred Asset Recovery Rider and Distribution Investment Recovery Rider. A portion of these increases have corresponding increases in other expense items below.
  - A $35 million increase due to OPCo's partial reversal in 2012 of a 2011 fuel provision related to CRES providers.

  These increases were partially offset by:
  - A $46 million decrease related to Ohio customers switching to alternative CRES providers. This decrease in Retail Margins is partially offset by an increase in Transmission Revenues related to CRES providers detailed below.
- **Transmission Revenues** increased $59 million primarily due to increased transmission revenues from Ohio customers who switched to alternative CRES providers.
- **Other Revenues** increased $51 million primarily due to an increase in revenues related to TCC's issuance of securitization bonds in March 2012. This increase in revenues from securitization bonds is partially offset by an increase in Depreciation and Amortization expense.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $43 million primarily due to the following:
  - A $70 million decrease related to the 2011 recording and subsequent 2012 reversal of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the PUCO's February 2012 rejection of the Ohio modified stipulation.

  These decreases were partially offset by:
  - A $13 million increase in storm-related expenses primarily in Ohio.
  - A $13 million increase due to expenses related to the 2012 sustainable cost reductions.
- **Depreciation and Amortization** expenses increased $12 million primarily due to the following :
  - A $51 million increase due to TCC's issuance of securitization bonds in March 2012. The increase in TCC's securitization related amortization is offset within Gross Margin.

  - An $11 million increase in amortization of Deferred Asset Recovery Rider assets as approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012. This increase in amortization is offset within Gross Margin.
  - A $9 million increase due to higher depreciable property balances primarily related to the Texas Automated Meter Infrastructure project.

  These increases were partially offset by:

  - A $39 million decrease due to amortization adjustment approved by the PUCO in the 2011 Ohio Distribution Base Rate Case effective January 2012.
  - A $23 million decrease due to amortization of carrying costs on deferred fuel as a result of the October 2011 PUCO remand order which allowed the POLR refund to be applied against any deferred fuel balances. The equity amortization was offset by amounts recognized in Carrying Costs Income.
- **Taxes Other Than Income Taxes** increased $11 million primarily due to increased property taxes.
- **Carrying Costs Income** decreased $351 million primarily due to the recognition in 2011 of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Income Tax Expense** decreased $18 million primarily due to a decrease in pretax book income and by the recording of state income tax adjustments.

GENERATION & MARKETING

Generation & Marketing	Years Ended December 31, 2013	2012	2011
	(in millions)		
Revenues	$ 3,665	$ 3,467	$ 3,894
Fuel, Purchased Electricity and Other	2,305	2,065	2,215
Gross Margin	1,360	1,402	1,679
Other Operation and Maintenance	523	507	537
Asset Impairments and Other Related Charges	154	287	90
Depreciation and Amortization	236	349	304
Taxes Other Than Income Taxes	54	62	60
Operating Income	393	197	688
Interest and Investment Income	2	1	4
Interest Expense	(55)	(83)	(87)
Income Before Income Tax Expense	340	115	605
Income Tax Expense	112	15	166
Income Before Extraordinary Item	$ 228	$ 100	$ 439

Summary of MWhs Generated for Generation & Marketing

	Years Ended December 31, 2013	2012	2011
	(in millions of MWhs)		
Fuel Type:			
Coal	38	37	45
Natural Gas	6	11	7
Wind	1	1	1
Total MWhs	45	49	53

2013 Compared to 2012

Reconciliation of Year Ended December 31, 2012 to Year Ended December 31, 2013
Income from Generation & Marketing Before Extraordinary Item
(in millions)

Year Ended December 31, 2012	$	100
Changes in Gross Margin:		
Generation		(44)
Retail, Trading and Marketing		4
Other		(2)
Total Change in Gross Margin		(42)
Changes in Expenses and Other:		
Other Operation and Maintenance		(16)
Asset Impairments and Other Related Charges		133
Depreciation and Amortization		113
Taxes Other Than Income Taxes		8
Interest and Investment Income		1
Interest Expense		28
Total Change in Expenses and Other		267
Income Tax Expense		(97)
Year Ended December 31, 2013	$	228

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, purchased electricity and certain costs of service for retail operations were as follows:

- **Generation** decreased $44 million primarily due to the following:
  - A $336 million decrease in affiliated sales to OPCo primarily due to customers switching to alternative CRES providers as well as a reduction in industrial usage.

  This decrease was partially offset by the following:
  - A $221 million net increase in sales to AEP affiliates under the Interconnection Agreement.
  - A $63 million decrease in fuel expenses due to a reduction in generation at the Lawrenceburg Plant.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $16 million primarily due to a 2013 adjustment of $14 million to impaired plant investment as a result of changes to asset retirement obligations for asbestos removal and retirement of ash disposal facilities at impaired plants.
- **Asset Impairments and Other Related Charges** decreased $133 million due to the following:
  - A 2012 impairment of $287 million for certain Ohio generation plants, which includes $13 million of related materials and supplies inventory.

  This decrease was partially offset by:
  - A 2013 impairment of $154 million for Muskingum River Plant, Unit 5.

- **Depreciation and Amortization** expenses decreased $113 million primarily due to depreciation ceasing on certain Ohio generation plants that were impaired in November 2012 and June 2013.
- **Interest Expense** decreased $28 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $97 million primarily due to an increase in pretax book income and by the recording of state income tax adjustments.

2012 Compared to 2011

Reconciliation of Year Ended December 31, 2011 to Year Ended December 31, 2012
Income from Generation & Marketing Before Extraordinary Item
(in millions)

Year Ended December 31, 2011	$	439
Changes in Gross Margin:		
Generation		(363)
Retail, Trading and Marketing		86
Total Change in Gross Margin		(277)
Changes in Expenses and Other:		
Other Operation and Maintenance		30
Asset Impairments and Other Related Charges		(197)
Depreciation and Amortization		(45)
Taxes Other Than Income Taxes		(2)
Interest and Investment Income		(3)
Interest Expense		4
Total Change in Expenses and Other		(213)
Income Tax Expense		151
Year Ended December 31, 2012	$	100

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, purchased electricity and certain costs of service for retail operations were as follows:

- **Generation** decreased $363 million primarily due to the following:
  - A $396 million decrease in affiliated sales to OPCo primarily due to customer switching to alternative CRES providers.

  This decrease was partially offset by:
  - A $29 million increase in non-affiliated sales due to increased sales to Buckeye Power, Inc. for back-up energy under the Cardinal Station Agreement.
- **Retail, Trading and Marketing** increased $86 million primarily due to the March 2012 acquisition of BlueStar.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $30 million primarily due to the following:
  - A $78 million decrease in plant outage and other plant operating and maintenance expenses.

  This decrease was partially offset by:
  - A $47 million increase in AEP Energy labor and sales expenses due to the acquisition of BlueStar in March 2012.
- **Asset Impairments and Other Related Charges** increased $197 million due to the following:

- A 2012 impairment of $287 million for certain Ohio generation plants, which includes $13 million of related materials and supplies inventory.

  This increase was partially offset by:
  - A 2011 plant impairment of $48 million for Sporn Plant, Unit 5.
  - A 2011 plant impairment of $42 million for FGD project at Muskingum River Plant, Unit 5.
- **Depreciation and Amortization** expenses increased $45 million primarily due to the following:
  - A $58 million increase due to shortened depreciable lives for certain AGR generation plants effective December 2011. The book value of these plants was fully impaired in November 2012.
  - Overall higher depreciable property balances.

  These increases were partially offset by:
  - A $13 million decrease in depreciation due to the 2011 plant impairment of Sporn Plant, Unit 5.
- **Income Tax Expense** decreased $151 million primarily due to a decrease in pretax book income.

AEP TRANSMISSION HOLDCO

2013 Compared to 2012

Income Before Extraordinary Item from our AEP Transmission Holdco segment increased from $43 million in 2012 to $80 million in 2013 primarily due to an increase in investments by our wholly-owned transmission subsidiaries and ETT.

2012 Compared to 2011

Income Before Extraordinary Item from our AEP Transmission Holdco segment increased from $30 million in 2011 to $43 million in 2012 primarily due to an increase in investments by ETT and our wholly-owned transmission subsidiaries.

AEP RIVER OPERATIONS

2013 Compared to 2012

Income Before Extraordinary Item from our AEP River Operations segment decreased from $15 million in 2012 to $12 million in 2013 primarily due to significant reductions in export grain and coal demand. In addition, low water levels in the first and fourth quarters of 2013 limited barge loads and tow sizes.

2012 Compared to 2011

Income Before Extraordinary Item from our AEP River Operations segment decreased from $45 million in 2011 to $15 million in 2012 primarily due to the 2012 drought, which had significant impacts on river conditions and crop yields, resulting in reduced grain exports.

CORPORATE AND OTHER

2013 Compared to 2012

Income Before Extraordinary Item from Corporate and Other increased from a loss of $88 million in 2012 to income of $125 million in 2013 primarily due to a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in 2013 as well as a reduction in interest expense associated with the early retirement of debt in 2012.

2012 Compared to 2011

Income Before Extraordinary Item from Corporate and Other decreased from a loss of $52 million in 2011 to a loss of $88 million in 2012 primarily due to costs associated with the early retirement of debt in 2012 and the 2012 adjustment of a U.K. Windfall Tax provision as a result of a related Supreme Court case, partially offset by a loss incurred in 2011 related to the settlement of litigation with BOA and Enron.

AEP SYSTEM INCOME TAXES

2013 Compared to 2012

Income Tax Expense increased $80 million primarily due to an increase in pretax book income and the recording of state income tax adjustments partially offset by a favorable U.K. Windfall Tax decision by the U.S. Supreme Court in the second quarter of 2013.

2012 Compared to 2011

Income Tax Expense decreased $214 million primarily due to a decrease in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron recorded in 2011, partially offset by the recording of federal and state income tax adjustments.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31, 2013		December 31, 2012	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 18,377	52.2 %	$ 17,757	52.3 %
Short-term Debt	757	2.1	981	2.9
Total Debt	19,134	54.3	18,738	55.2
AEP Common Equity	16,085	45.7	15,237	44.8
Noncontrolling Interests	1	-	-	-
Total Debt and Equity Capitalization	$ 35,220	100.0 %	$ 33,975	100.0 %

Our ratio of debt-to-total capital decreased from 55.2% as of December 31, 2012 to 54.3% as of December 31, 2013 primarily due to an increase in common equity, partially offset by a net increase in debt issuances, including the issuance of $647 million of securitization bonds.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. As of December 31, 2013, we had $3.5 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a receivables securitization agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Commercial Paper Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. As of December 31, 2013, our available liquidity was approximately $3.4 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,750	June 2016
Revolving Credit Facility	1,750	July 2017
Total	3,500	
Cash and Cash Equivalents	118	
Total Liquidity Sources	3,618	
Less: AEP Commercial Paper Outstanding	57	

Letters of Credit Issued	170
Net Available Liquidity	$ 3,391

We have credit facilities totaling $3.5 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.2 billion.

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2013 was $904 million. The weighted-average interest rate for our commercial paper during 2013 was 0.32%.

Other Credit Facilities

In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to fund certain OPCo maturities on an interim basis and to facilitate OPCo's corporate separation of generation assets from transmission and distribution. As of December 31, 2013, the $1 billion term credit facility was entirely drawn. Repayments prior to maturity are permitted. However, any amount that is repaid may not be re-borrowed and is a permanent reduction of the term credit facility.

In January 2014, we issued letters of credit utilizing the entire amount available under an $85 million uncommitted facility signed in October 2013. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

Financing Plan

As of December 31, 2013, we have $1.5 billion of long-term debt due within one year which includes $879 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current. Also included in our long-term debt due within one year is $413 million of securitization bonds and DCC Fuel notes payable which will be repaid. We plan to refinance the majority of our other maturities due within one year.

Securitized Accounts Receivables

In 2013, we amended our receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2014 and the remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2014 on or before its maturity.

West Virginia Securitization of Regulatory Assets

In September 2013, the WVPSC approved a settlement agreement filed by APCo, WPCo and intervenors which authorized APCo to securitize $376 million, plus upfront financing costs, related primarily to the December 2011 under-recovered Expanded Net Energy Charge (ENEC) deferral balance. In November 2013, APCo issued $380 million of Securitization Bonds to securitize the under-recovered ENEC deferral balance, including $4 million of upfront financing costs, with a final maturity date of August 2031. APCo implemented a new securitization rider which was offset by an equal reduction in ENEC revenues, with no overall change in total revenues.

Ohio Securitization of Regulatory Assets

In March 2013, the PUCO approved OPCo's request to securitize the Deferred Asset Recovery Rider (DARR) balance. In August 2013, OPCo issued $267 million of Securitization Bonds, with a final maturity date of July 2020, to securitize the DARR balance. As a result of the securitization, recovery through the DARR has ceased and has been replaced by the Deferred Asset Phase-in Rider which will recover the securitized assets.

Debt Covenants and Borrowing Limitations

Our credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our credit agreements. Debt as defined in the credit agreements excludes securitization bonds and debt of AEP Credit. As of December 31, 2013, this contractually-defined percentage was 50.4%. Nonperformance under these covenants could result in an event of default under these credit agreements. As of

December 31, 2013, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements. This condition also applies in a majority of our non-exchange traded commodity contracts and would similarly allow lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. As of December 31, 2013, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.50 per share in January 2014. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. However, we do not believe these restrictions will have any significant impact on Parent's ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

We do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject us to additional collateral demands under adequate assurance clauses under our derivative and non-derivative energy contracts.

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 279	$ 221	$ 294
Net Cash Flows from Operating Activities	4,106	3,804	3,788
Net Cash Flows Used for Investing Activities	(3,818)	(3,391)	(2,890)
Net Cash Flows Used for Financing Activities	(449)	(355)	(971)
Net Increase (Decrease) in Cash and Cash Equivalents	(161)	58	(73)
Cash and Cash Equivalents at End of Period	$ 118	$ 279	$ 221

Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Years Ended December 31,		
	2013	2012	2011
		(in millions)	
Net Income	$ 1,484	$ 1,262	$ 1,949
Depreciation and Amortization	1,743	1,782	1,655
Other	879	760	184
Net Cash Flows from Operating Activities	$ 4,106	$ 3,804	$ 3,788

Net Cash Flows from Operating Activities were $4.1 billion in 2013 consisting primarily of Net Income of $1.5 billion, $1.7 billion of noncash Depreciation and Amortization and $226 million of Asset Impairments related to Muskingum River Plant, Unit 5, Big Sandy and Amos Plants, partially offset by $214 million of Ohio capacity deferrals as a result of a 2012 PUCO order. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Deferred Income Taxes increased primarily due to provisions in the Taxpayer Relief Act of 2012 and an increase in tax versus book temporary differences from operations. Significant changes in other items include the favorable impact of a decrease in fuel inventory and net cash flows for Accrued Taxes as a result of the recognition of the tax benefit related to the U.K. Windfall Tax.

Net Cash Flows from Operating Activities were $3.8 billion in 2012 consisting primarily of Net Income of $1.3 billion, $1.8 billion of noncash Depreciation and Amortization and $287 million in Asset Impairments related to certain Ohio generation assets. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. A significant change in other items includes the unfavorable impact of an increase in fuel inventory due to the mild winter weather. Deferred Income Taxes increased primarily due to provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act and an increase in tax versus book temporary differences from operations. During 2012, we also contributed $200 million to our qualified pension trust.

Net Cash Flows from Operating Activities were $3.8 billion in 2011 consisting primarily of Net Income of $1.9 billion and $1.7 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Following a Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance and the PUCT's approval of a stipulation agreement, we recorded an Extraordinary Item, Net of Tax of $373 million for the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts and the reversal of tax related regulatory credits. We also recorded $393 million in Carrying Costs Income primarily related to the Texas restructuring appeals. A significant change in other items includes the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to bonus depreciation provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act, the settlement with BOA and Enron and an increase in tax versus book temporary differences from operations. In February 2011, we paid $425 million to BOA of which $211 million was used to settle litigation with BOA and Enron. The remaining $214 million was used to acquire cushion gas as discussed in Investing Activities below. During 2011, we also contributed $450 million to our qualified pension trust.

Investing Activities

	Years Ended December 31, 2013	2012	2011
		(in millions)	
Construction Expenditures	$ (3,624)	$ (3,025)	$ (2,669)
Acquisitions of Nuclear Fuel	(154)	(107)	(106)
Acquisitions of Assets/Businesses	(32)	(94)	(19)
Acquisitions of Cushion Gas from BOA	-	-	(214)
Proceeds from Sales of Assets	21	18	123
Other	(29)	(183)	(5)
Net Cash Flows Used for Investing Activities	$ (3,818)	$ (3,391)	$ (2,890)

Net Cash Flows Used for Investing Activities were $3.8 billion in 2013 primarily due to Construction Expenditures for environmental, distribution and transmission investments.

Net Cash Flows Used for Investing Activities were $3.4 billion in 2012 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. Acquisitions of Assets/Businesses include our March 2012 purchase of BlueStar for $70 million.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2011 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. We paid $214 million to BOA for cushion gas as part of a litigation settlement.

Financing Activities

	Years Ended December 31,		
	2013	**2012**	**2011**
		(in millions)	
Issuance of Common Stock, Net	$ 84	$ 83	$ 92
Issuance/Retirement of Debt, Net	385	544	(33)
Proceeds from Nuclear Fuel Sale/Leaseback	110	-	-
Retirement of Cumulative Preferred Stock	-	-	(64)
Dividends Paid on Common Stock	(954)	(916)	(898)
Other	(74)	(66)	(68)
Net Cash Flows Used for Financing Activities	$ (449)	$ (355)	$ (971)

Net Cash Flows Used for Financing Activities in 2013 were $449 million. Our net debt issuances were $385 million. The net issuances included issuances of $745 million of senior unsecured notes, $1 billion draws on a $1 billion term credit facility, $647 million of securitization bonds, $328 million of notes payable and other debt and $305 million of pollution control bonds offset by retirements of $1.8 billion of senior unsecured and other debt notes, $331 million of pollution control bonds, $243 million of securitization bonds and a decrease in short-term borrowing of $224 million. We paid common stock dividends of $954 million. See Note 14 – Financing Activities.

Net Cash Flows Used for Financing Activities in 2012 were $355 million. Our net debt issuances were $544 million. The net issuances included issuances of $1.7 billion of senior unsecured notes, $800 million of securitization bonds, $287 million of notes payable and other debt and $65 million of pollution control bonds offset by retirements of $902 million of senior unsecured and other debt notes, $315 million of junior subordinate debentures, $220 million of pollution control bonds, $206 million of securitization bonds and a decrease in short-term borrowing of $669 million. We paid common stock dividends of $916 million.

Net Cash Flows Used for Financing Activities in 2011 were $971 million. Our net debt retirements were $33 million. The net retirements included retirements of $727 million of senior unsecured and other debt notes, $778 million of pollution control bonds and $159 million of securitization bonds offset by issuances of $710 million of notes, $627 million of pollution control bonds and an increase in short-term borrowing of $304 million. We paid common stock dividends of $898 million and $64 million to retire all of our subsidiaries' preferred stocks.

The following financing activities occurred during 2013:

AEP Common Stock:

- During 2013, we issued 2.1 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $84 million.

Debt:

- During 2013, we issued approximately $3 billion of long-term debt, including $1 billion drawn on a term credit facility, $745 million of senior notes at interest rates ranging from 2.73% to 5.32% and $647 million of securitization bonds at interest rates ranging from 0.96% to 3.77%. We also issued $190 million of pollution control revenue bonds at interest rates ranging from 3.25% to 4%, $115 million of pollution control revenue bonds at variable interest rates and $328 million of other debt at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2013, we entered no interest rate derivatives and settled $379 million of such transactions. The settlements resulted in net cash payments of $26 million. As of December 31, 2013, we had in place $820 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2014:

- In January 2014, TCC retired $112 million of Securitization Bonds.
- In January and February 2014, I&M retired $24 million of Notes Payable related to DCC Fuel.
- In January 2014, OPCo retired $225 million of 4.85% Senior Unsecured Notes due in 2014.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $3.8 billion of construction expenditures excluding equity AFUDC for 2014. For 2015 and 2016, we forecast construction expenditures of $3.8 billion each year. The expenditures are generally for transmission, distribution and required environmental investment to comply with Federal EPA rules. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The 2014 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	2014 Budgeted Construction Expenditures					
Segment	**Environmental**	**Generation**	**Transmission**	**Distribution**	**Other**	**Total**
			(in millions)			
Vertically Integrated Utilities	$ 467	$ 410	$ 465	$ 564	$ 67	$ 1,973
Transmission and Distribution Utilities	7	5	340	494	36	882
Generation & Marketing	114	63	-	-	14	191

AEP Transmission Holdco	-	-	786	-	1	787
AEP River Operations	-	-	-	-	9	9
Corporate and Other	-	-	-	-	3	3
Total	$ 588	$ 478	$ 1,591	$ 1,058	$ 130	$ 3,845

OFF-BALANCE SHEET ARRANGEMENTS

Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements.

Rockport Plant, Unit 2

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for AEGCo and I&M are $665 million and $665 million, respectively, as of December 31, 2013.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $28 million for the remaining railcars as of December 31, 2013. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five-year renewal. As of December 31, 2013, the maximum potential loss was approximately $19 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTRACTUAL OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations as of December 31, 2013:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Short-term Debt (a)	$ 757	$ -	$ -	$ -	$ 757
Interest on Fixed Rate Portion of Long-term Debt (b)	784	1,442	1,250	6,283	9,759
Fixed Rate Portion of Long-term Debt (c)	988	2,284	2,853	10,328	16,453
Variable Rate Portion of Long-term Debt (d)	561	1,382	6	-	1,949
Capital Lease Obligations (e)	135	208	123	215	681
Noncancelable Operating Leases (e)	288	514	445	862	2,109
Fuel Purchase Contracts (f)	2,362	3,391	2,235	2,649	10,637
Energy and Capacity Purchase Contracts	195	410	457	2,634	3,696
Construction Contracts for Capital Assets (g)	807	1,123	931	1,797	4,658
Total	$ 6,877	$ 10,754	$ 8,300	$ 24,768	$ 50,699

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding as of December 31, 2013 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.02% and 1.91% as of December 31, 2013.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents only capital assets for which we have 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.

Our $51 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2013, we expect to make contributions to our pension plans totaling $80 million in 2014. Estimated contributions of $78 million in 2015 and $84 million in 2016 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the accumulated benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 99.9% funded as of December 31, 2013.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. As of December 31, 2013, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 170	$ -	$ -	$ -	$ 170
Guarantees of the Performance of Outside Parties (b)	-	-	-	115	115
Guarantees of Our Performance (c)	592	-	10	58	660
Total Commercial Commitments	$ 762	$ -	$ 10	$ 173	$ 945

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $170 million with maturities ranging from February 2014 to April 2015. See “Letters of Credit” section of Note 6.
(b) See “Guarantees of Third-Party Obligations” section of Note 6.
(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The Small Business Jobs Act extended the time for claiming bonus depreciation and increased the deduction to 100% for 2011 and decreased the deduction to 50% for 2012. The American Taxpayer Relief Act of 2012 provided for the extension of several business and energy industry tax deductions and credits, including the one-year extension of the 50% bonus depreciation to 2013. The enacted provisions had no material impact on net income or financial condition but did have a favorable impact on cash flows in 2013.

CYBER SECURITY

Cyber security presents a heightened risk for electric utility systems because a cyber-attack could affect critical energy infrastructure. Breaches to the cyber security of the grid or to our system are potentially disruptive to people, property and commerce and create risk for our business, investors and customers. In February 2013, President Obama signed an executive order that addresses how government agencies will operate and support the functions in cyber security as well as redefine how the government interfaces with critical infrastructure, such as the electric grid. We already operate under regulatory cyber security standards to protect critical infrastructure. The cyber security framework that is being developed through this executive order will be reviewed by the FERC and the U.S. Department of Energy. We are participating in the process by submitting feedback through our industry trade group and sharing best practices already in place. We protect our critical cyber assets, such as our data centers, power plants, transmission operations centers and business network, using multiple layers of cyber security and authentication. We constantly scan the system for risks or threats.

Cyber hackers have been able to breach a number of very secure facilities, from federal agencies, banks and retailers to social media sites. As these events become known and develop, we continually assess our own cyber security tools and processes to determine where we might need to strengthen our defenses.

In recent years, we have taken additional steps to enhance our capabilities for identifying risks or threats and have shared those threats with our utility peers, industry and federal agencies. We operate our own Cyber Security Operations Center. Funding for this included a grant from the American Recovery and Reinvestment Act – U.S. Department of Energy Smart Grid Demonstration Program. This facility was initially designed as a pilot cyber threat and information-sharing center specifically for the electric sector and today is fully operational.

In 2013, as part of our industry's continuing program to advance threat sharing and coordination, we participated in the North American Electric Reliability Corporation (NERC) GridEx II exercise. This effort, led by NERC, tested and developed the coordination and interaction between utilities and various government agencies relative to potential cyber and physical threats against the nation's electric grid.

In 2012, we signed a cooperative research and development agreement with the Department of Homeland Security's Office of Cyber Security and Communications, further enhancing our ability to directly exchange information about cyber threats. In addition, we continue to partner with a number of federal and industry groups to advance the national capabilities of cyber security. We are working with the U.S. Department of Energy on several projects covering advanced cyber security and assessment tools.

We have partnered with a major defense contractor who has significant cyber security experience and technical capabilities developed through their work with the U.S. Department of Defense. We work with a consortium of other utilities across the country, learning how best to share information about potential threats and collaborating with each other. We continue to work with a nonaffiliated entity to conduct several seminars each year about recognizing and investigating cyber vulnerabilities. Through these types of efforts, we are working to protect ourselves while helping our industry advance its cyber security capabilities.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES AND ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosures relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

Our 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.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of expense and income recognition with regulated revenues. We also record liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Similarly, we record regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 5 for further detail related to regulatory assets and regulatory liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues for our Vertically Integrated Utilities segment were $(9) million, $13 million and $(57) million for the years ended December 31, 2013, 2012 and 2011, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Vertically Integrated Utilities segment were $283 million and $292 million as of December 31, 2013 and 2012, respectively.

The changes in unbilled electric utility revenues for our Transmission and Distribution Utilities segment were $(22) million, $(12) million and $(24) million for the years ended December 31, 2013, 2012 and 2011, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Transmission and Distribution Utilities segment were $165 million and $187 million as of December 31, 2013 and 2012, respectively.

In March 2012, our Generation & Marketing segment acquired an independent retail electric supplier. The change in unbilled electric utility revenues for our Generation & Marketing segment was $10 million and $34 million for the years ended December 31, 2013 and 2012, respectively. Accrued unbilled revenues for the Generation & Marketing segment were $41 million and $31 million as of December 31, 2013 and 2012, respectively.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation (generation plus purchases less sales) less the current month’s billed KWh plus the prior month’s unbilled KWh. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWh to the current month and previous month, on a cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWh. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

For certain contracts, we calculate unbilled revenues by contract using the most recent historic daily activity adjusted for significant known changes in usage.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based primarily on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We calculate credit adjustments on our risk management contracts using estimated default probabilities and recovery rates relative to our counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, we assess hedge effectiveness and evaluate a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of “Property, Plant and Equipment” accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held-and-used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. Performing an impairment evaluation involves a significant degree of estimation and judgment in areas such as identifying circumstances that indicate an impairment may exist, identifying and grouping affected assets and developing the undiscounted and discounted future cash flows (used to estimate fair value in the absence of market-based value, in some instances) associated with the asset. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of an impairment charge could be offset by the establishment of a regulatory asset if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. Cash flow estimates are based on relevant information available at the time the estimates are made. Estimates of future cash flows are, by nature, highly uncertain and may vary significantly from actual results. Also, when measuring fair value, management evaluates the characteristics of the asset or liability to determine if market participants would take those characteristics into account when pricing the asset or liability at the measurement date. Such characteristics include, for example, the condition and location of the asset or restrictions of the use of the asset. We perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of an asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law for participants in the Qualified Plan (collectively the Pension Plans). Additionally, we entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide health and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively referred to as the 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. See Note 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost (credit) of the Plans:

Net Periodic Benefit Cost (Credit)	Years Ended December 31, 2013	2012	2011
		(in millions)	
Pension Plans	$ 180	$ 134	$ 118
Postretirement Plans	(17)	89	73

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2014, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets and changes in tax rates which affect a portion of the Postretirement Plans' assets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 6% for the Qualified Plan and 6.75% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	2014 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2014 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	30 %	8.00 %	66 %	7.80 %
Fixed Income	55 %	4.60 %	33 %	4.40 %
Other Investments	15 %	7.00 %	- %	- %
Cash and Cash Equivalents	- %	- %	1 %	3.00 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 6% and 6.75% are reasonable estimates of the long-term rate of return on the Plans' assets. The Pension Plans' assets had an actual gain of 8.1% and 13.8% for the years ended December 31, 2013 and 2012, respectively. The Postretirement Plans' assets had an actual gain of 14.3% and 15.4% for the years ended December 31, 2013 and 2012, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income 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 based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2013, we had cumulative gains of approximately $207 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial gains may result in decreases in the future pension costs depending on several factors, including whether such gains at each measurement date exceed the corridor in accordance with “Compensation – Retirement Benefits” accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which 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. The discount rate as of December 31, 2013 under this method was 4.7% for the Qualified Plan, 4.55% for the Nonqualified Plans and 4.7% for the Postretirement Plans. Due to the effect of the unrecognized actuarial gains and based on an expected rate of return on the Pension Plans’ assets of 6%, discount rates of 4.7% and 4.55% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $161 million,

$113 million and $109 million in 2014, 2015 and 2016, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 6.75%, a discount rate of 4.7% and various other assumptions, we estimate credits will approximate $77 million, $82 million and $82 million in 2014, 2015 and 2016, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical costs was capped reducing our future exposure to medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. This change reduced costs of the plan beginning in 2013 as shown by the estimated credits for Postretirement Plans in the previous paragraph.

The value of the Pension Plans' assets remained unchanged at $4.7 billion as of December 31, 2013 and December 31, 2012 primarily due to investment returns offsetting benefit payments. During 2013, the Qualified Plan paid $324 million and the Nonqualified Plans paid $7 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.7 billion as of December 31, 2013 from $1.6 billion as of December 31, 2012 primarily due to investment returns and contributions by the company and the participants in excess of benefit payments. The Postretirement Plans paid $140 million in benefits to plan participants during 2013.

Nature of Estimates Required

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	**-0.5%**	**+0.5%**	**-0.5%**
	(in millions)			
Effect on December 31, 2013 Benefit Obligations				
Discount Rate	$ (233)	$ 254	$ (71)	$ 78
Compensation Increase Rate	13	(12)	NA	NA
Cash Balance Crediting Rate	43	(39)	NA	NA
Health Care Cost Trend Rate	NA	NA	25	(28)
Effect on 2013 Periodic Cost				
Discount Rate	(12)	13	(4)	4
Compensation Increase Rate	4	(4)	NA	NA
Cash Balance Crediting Rate	11	(11)	NA	NA
Health Care Cost Trend Rate	NA	NA	4	(4)
Expected Return on Plan Assets	(21)	21	(8)	8

NA Not applicable.

ACCOUNTING PRONOUNCEMENTS

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, we cannot determine the impact on the reporting of our operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, financial instruments, leases, insurance, hedge accounting and consolidation policy. The ultimate pronouncements resulting from these and future projects could have an impact on our future net income and financial position.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

Our Vertically Integrated Utilities segment is exposed to certain market risks as a major power producer and through its transactions in power, coal, natural gas and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk as we occasionally procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Transmission and Distribution Utilities segment is exposed to FTR price risk as it relates to congestion during the June 2012 – May 2015 Ohio ESP period. Additional risk includes interest rate risk.

Our Generation & Marketing segment conducts marketing, risk management and retail activities in ERCOT, PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates. In addition, our Generation & Marketing segment is also exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, natural gas and coal trading and marketing contracts.

We employ risk management contracts including physical forward purchase-and-sale contracts and financial forward purchase-and-sale contracts. We engage in risk management of power, coal, natural gas and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the Commercial Operations, Energy Supply, and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (Regulated Risk Committee) and the Energy Supply Risk Committee (Competitive Risk Committee) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The Regulated Risk Committee consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Generation, Senior Vice President of Commercial Operations and Chief Risk Officer. The Competitive Risk Committee consists of our Chief Operating Officer, Chief Financial Officer, Executive Vice President of Energy Supply, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the respective committee.

The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2012:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2013

	Vertically Integrated Utilities	Transmission and Distribution Utilities	Generation and Marketing	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets as of December 31, 2012	$ 39	$ (1)	$ 158	$ 196
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(16)	1	(32)	(47)
Fair Value of New Contracts at Inception When Entered During the Period (a)	-	-	16	16
Changes in Fair Value Due to Market Fluctuations During the Period (b)	-	-	15	15
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	9	3	-	12
Total MTM Risk Management Contract Net Assets as of December 31, 2013	$ 32	$ 3	$ 157	192
Commodity Cash Flow Hedge Contracts				1
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(2)

Fair Value Hedge Contracts		(10)
Collateral Deposits		9
Total MTM Derivative Contract Net Assets as of December 31, 2013	$	190

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

We limit credit risk in our 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. We use Moody's Investors Service, Standard & 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.

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2013, our credit exposure net of collateral to sub investment grade counterparties was approximately 8.7%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2013, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 630	$ 7	$ 623	2	$ 290
Split Rating	-	-	-	-	-
Noninvestment Grade	-	-	-	-	-
No External Ratings:					
Internal Investment Grade	79	-	79	4	45
Internal Noninvestment Grade	78	11	67	3	46
Total as of December 31, 2013	$ 787	$ 18	$ 769	9	$ 381
Total as of December 31, 2012	$ 807	$ 13	$ 794	7	$ 338

In addition, we are exposed to credit risk related to our participation in RTOs. For each of the RTOs in which we participate, this risk is generally determined based on our proportionate share of member gross activity over a specified period of time.

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2013, a near term typical change in commodity prices is not expected to materially impact net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the trading portfolio for the periods indicated:

VaR Model

Twelve Months Ended **Twelve Months Ended**

December 31, 2013				December 31, 2012			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 1	$ -	$ -	$ -	$ 1	$ -	$ -

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last several years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee, Regulated Risk Committee, or Competitive Risk Committee as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2013 and 2012, the estimated EaR on our debt portfolio for the following twelve months was $32 million and $42 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2013 and 2012,and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013, in conformity with accounting principles generally accepted in the United States of America.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control—Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 25, 2014 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of
American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2013, based on criteria established in *Internal Control — Integrated Framework (1992)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on the criteria established in Internal Control — Integrated Framework (1992) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2013 of the Company and our report dated February 25, 2014 expressed an unqualified opinion on those financial statements.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2014

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a- 15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2013. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO 1992) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2013.

AEP's independent registered public accounting firm has issued an attestation report on AEP's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2013, 2012 and 2011
(in millions, except per-share and share amounts)

	Years Ended December 31, 2013	2012	2011
REVENUES			
Vertically Integrated Utilities	$ 9,347	$ 8,785	$ 8,942
Transmission and Distribution Utilities	4,279	4,659	4,982
Generation & Marketing	1,208	882	563
Other Revenues	523	619	629
TOTAL REVENUES	15,357	14,945	15,116
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,068	4,111	4,421
Purchased Electricity for Resale	1,491	1,169	1,191
Other Operation	2,904	2,962	2,868
Maintenance	1,179	1,115	1,236
Asset Impairments and Other Related Charges	226	300	139
Depreciation and Amortization	1,743	1,782	1,655
Taxes Other Than Income Taxes	891	850	824
TOTAL EXPENSES	12,502	12,289	12,334
OPERATING INCOME	2,855	2,656	2,782
Other Income (Expense):			
Interest and Investment Income	58	8	27
Carrying Costs Income	30	53	393
Allowance for Equity Funds Used During Construction	73	93	98
Interest Expense	(906)	(988)	(933)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	2,110	1,822	2,367
Income Tax Expense	684	604	818
Equity Earnings of Unconsolidated Subsidiaries	58	44	27
INCOME BEFORE EXTRAORDINARY ITEM	1,484	1,262	1,576
EXTRAORDINARY ITEM, NET OF TAX	-	-	373
NET INCOME	1,484	1,262	1,949
Net Income Attributable to Noncontrolling Interests	4	3	3
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,480	1,259	1,946

Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,480	$ 1,259	$ 1,941
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	486,619,555	484,682,469	482,169,282
BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 3.04	$ 2.60	$ 3.25
Extraordinary Item, Net of Tax	-	-	0.77
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.04	$ 2.60	$ 4.02
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	487,040,956	485,084,694	482,460,328
DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Item	$ 3.04	$ 2.60	$ 3.25
Extraordinary Item, Net of Tax	-	-	0.77
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 3.04	$ 2.60	$ 4.02

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	Years Ended December 31,		
	2013	**2012**	**2011**
Net Income	$ 1,484	$ 1,262	$ 1,949
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $8, $8 and $18 in 2013, 2012 and 2011, Respectively	15	(15)	(34)
Securities Available for Sale, Net of Tax of $1, $1 and $1 in 2013, 2012 and 2011, Respectively	3	2	(2)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $12, $16 and $13 in 2013, 2012 and 2011, Respectively	22	31	24
Pension and OPEB Funded Status, Net of Tax of $95, $62 and $41 in 2013, 2012 and 2011, Respectively	177	115	(77)
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	217	133	(89)
TOTAL COMPREHENSIVE INCOME	1,701	1,395	1,860
Total Comprehensive Income Attributable to Noncontrolling Interests	4	3	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,697	1,392	1,857
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	-	-	5
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,697	$ 1,392	$ 1,852

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends ($1.85/share)				(894)		(4)	(898)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Loss on Reacquired Preferred Stock			(4)				(4)
Capital Stock Expense			(16)				(16)
Other Changes in Equity			11	(2)		2	11
Net Income				1,946		3	1,949
Other Comprehensive Loss					(89)		(89)
TOTAL EQUITY – DECEMBER 31, 2011	504	3,274	5,970	5,890	(470)	1	14,665
Issuance of Common Stock	2	15	68				83
Common Stock Dividends ($1.88/share)				(913)		(3)	(916)
Other Changes in Equity			11			(1)	10
Net Income				1,259		3	1,262
Other Comprehensive Income					133		133
TOTAL EQUITY – DECEMBER 31, 2012	506	3,289	6,049	6,236	(337)	-	15,237
Issuance of Common Stock	2	14	70				84
Common Stock Dividends ($1.95/share)				(950)		(4)	(954)
Other Changes in Equity			12			1	13
Net Income				1,480		4	1,484
Other Comprehensive Income					217		217
Pension and OPEB Adjustment Related to Mitchell Plant					5		5
TOTAL EQUITY – DECEMBER 31, 2013	508	$ 3,303	$ 6,131	$ 6,766	$ (115)	$ 1	$ 16,086

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2013 and 2012
(in millions)

	December 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 118	$ 279
Other Temporary Investments (December 31, 2013 and 2012 Amounts Include $335 and $311, Respectively, Related to Transition Funding, Phase-in-Recovery Funding, Consumer Rate Relief Funding and EIS)	353	324
Accounts Receivable:		
Customers	746	685
Accrued Unbilled Revenues	157	195
Pledged Accounts Receivable - AEP Credit	945	856
Miscellaneous	72	171
Allowance for Uncollectible Accounts	(60)	(36)
Total Accounts Receivable	1,860	1,871
Fuel	701	844
Materials and Supplies	722	675
Risk Management Assets	160	191
Regulatory Asset for Under-Recovered Fuel Costs	80	88
Margin Deposits	70	76
Prepayments and Other Current Assets	246	241
TOTAL CURRENT ASSETS	4,310	4,589
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	25,074	26,279
Transmission	10,893	9,846
Distribution	16,377	15,565
Other Property, Plant and Equipment (Including Plant to be Retired, Coal Mining and Nuclear Fuel)	5,470	3,945
Construction Work in Progress	2,471	1,819
Total Property, Plant and Equipment	60,285	57,454
Accumulated Depreciation and Amortization	19,288	18,691
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	40,997	38,763
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,376	5,106
Securitized Assets	2,373	2,117
Spent Nuclear Fuel and Decommissioning Trusts	1,932	1,706
Goodwill	91	91

Long-term Risk Management Assets	297	368
Deferred Charges and Other Noncurrent Assets	2,038	1,627
TOTAL OTHER NONCURRENT ASSETS	11,107	11,015
TOTAL ASSETS	$ 56,414	$ 54,367

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2013 and 2012
(dollars in millions)

	December 31, 2013	December 31, 2012
CURRENT LIABILITIES		
Accounts Payable	$ 1,266	$ 1,169
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	700	657
Other Short-term Debt	57	324
Total Short-term Debt	757	981
Long-term Debt Due Within One Year (December 31, 2013 and 2012 Amounts Include $416 and $367, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding, Consumer Rate Relief Funding and Sabine)	1,549	2,171
Risk Management Liabilities	90	155
Customer Deposits	299	316
Accrued Taxes	822	747
Accrued Interest	245	269
Regulatory Liability for Over-Recovered Fuel Costs	119	47
Other Current Liabilities	965	968
TOTAL CURRENT LIABILITIES	6,112	6,823
NONCURRENT LIABILITIES		
Long-term Debt (December 31, 2013 and 2012 Amounts Include $2,532 and $2,227, Respectively, Related to Transition Funding, DCC Fuel, Phase-in-Recovery Funding, Consumer Rate Relief Funding and Sabine)	16,828	15,586
Long-term Risk Management Liabilities	177	214
Deferred Income Taxes	10,300	9,252
Regulatory Liabilities and Deferred Investment Tax Credits	3,694	3,544
Asset Retirement Obligations	1,835	1,696
Employee Benefits and Pension Obligations	415	1,075
Deferred Credits and Other Noncurrent Liabilities	967	940
TOTAL NONCURRENT LIABILITIES	34,216	32,307
TOTAL LIABILITIES	40,328	39,130
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2013	2012

Shares Authorized	600,000,000	600,000,000		
Shares Issued	508,113,964	506,004,962		
(20,336,592 Shares were Held in Treasury as of December 31, 2013 and 2012)			3,303	3,289
Paid-in Capital			6,131	6,049
Retained Earnings			6,766	6,236
Accumulated Other Comprehensive Income (Loss)			(115)	(337)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY			16,085	15,237
Noncontrolling Interests			1	-
TOTAL EQUITY			16,086	15,237
TOTAL LIABILITIES AND EQUITY			$ 56,414	$ 54,367

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2013, 2012 and 2011
(in millions)

	Years Ended December 31,		
	2013	2012	2011
OPERATING ACTIVITIES			
Net Income	$ 1,484	$ 1,262	$ 1,949
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,743	1,782	1,655
Deferred Income Taxes	709	636	794
Gain on Settlement with BOA and Enron	-	-	(51)
Settlement of Litigation with BOA and Enron	-	-	(211)
Extraordinary Item, Net of Tax	-	-	(373)
Asset Impairments and Other Related Charges	226	300	139
Carrying Costs Income	(30)	(53)	(393)
Allowance for Equity Funds Used During Construction	(73)	(93)	(98)
Mark-to-Market of Risk Management Contracts	38	57	37
Amortization of Nuclear Fuel	131	136	137
Pension Contributions to Qualified Plan Trust	-	(200)	(450)
Property Taxes	(35)	(19)	(15)
Fuel Over/Under-Recovery, Net	62	157	(25)
Deferral of Ohio Capacity Costs, Net	(214)	(65)	-
Change in Other Noncurrent Assets	(184)	(171)	(112)
Change in Other Noncurrent Liabilities	3	127	307
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	5	(16)	107
Fuel, Materials and Supplies	122	(224)	176
Accounts Payable	95	(60)	(44)
Accrued Taxes, Net	85	174	193
Other Current Assets	5	(3)	37
Other Current Liabilities	(66)	77	29
Net Cash Flows from Operating Activities	4,106	3,804	3,788
INVESTING ACTIVITIES			
Construction Expenditures	(3,624)	(3,025)	(2,669)
Change in Other Temporary Investments, Net	(11)	(27)	8
Purchases of Investment Securities	(927)	(1,047)	(1,321)
Sales of Investment Securities	858	988	1,379
Acquisitions of Nuclear Fuel	(154)	(107)	(106)
Acquisitions of Assets/Businesses	(32)	(94)	(19)
Acquisition of Cushion Gas from BOA	-	-	(214)
Insurance Proceeds Related to Cook Plant Fire	72	-	-
Proceeds from Sales of Assets	21	18	123
Other Investing Activities	(21)	(97)	(71)
Net Cash Flows Used for Investing Activities	(3,818)	(3,391)	(2,890)

FINANCING ACTIVITIES			
Issuance of Common Stock, Net	84	83	92
Issuance of Long-term Debt	3,207	2,856	1,328
Commercial Paper and Credit Facility Borrowings	17	25	488
Change in Short-term Debt, Net	(221)	(654)	744
Retirement of Long-term Debt	(2,598)	(1,643)	(1,665)
Retirement of Cumulative Preferred Stock	-	-	(64)
Proceeds from Nuclear Fuel Sale/Leaseback	110	-	-
Commercial Paper and Credit Facility Repayments	(20)	(40)	(928)
Principal Payments for Capital Lease Obligations	(82)	(71)	(71)
Dividends Paid on Common Stock	(954)	(916)	(898)
Dividends Paid on Cumulative Preferred Stock	-	-	(2)
Other Financing Activities	8	5	5
Net Cash Flows Used for Financing Activities	(449)	(355)	(971)
Net Increase (Decrease) in Cash and Cash Equivalents	(161)	58	(73)
Cash and Cash Equivalents at Beginning of Period	279	221	294
Cash and Cash Equivalents at End of Period	$ 118	$ 279	$ 221

See Notes to Consolidated Financial Statements beginning on page 60.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

Our principal business is the generation, transmission and distribution of electric power. The subsidiaries that conduct most of these activities are regulated by the FERC under the Federal Power Act and the Energy Policy Act of 2005 and maintain accounts in accordance with the FERC and other regulatory guidelines. Most of these companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We provide competitive electric supply for residential, commercial and industrial customers in Ohio, Illinois and other deregulated electricity markets and also provide energy management solutions throughout the United States, including energy efficiency services through our independent retail electric supplier.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States and provide various energy-related services. In addition, our operations include nonregulated wind farms and barging operations.

Corporate Separation

Background

On December 31, 2013, based on FERC and PUCO orders which approved corporate separation of generation assets and associated liabilities, OPCo transferred its generation assets and related generation liabilities at net book value to AGR. In accordance with Ohio law, OPCo remains responsible to provide power and capacity to OPCo customers who have not switched electric providers. Effective January 1, 2014, OPCo will purchase power from both affiliated and nonaffiliated entities, subject to PUCO approval, to meet the energy and capacity needs of customers.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value its ownership (867 MW) in Amos Plant, Unit 3 to APCo. The transfer of these generation assets and associated liabilities was approved by the FERC, the Virginia SCC and the WVPSC.

On December 31, 2013, subsequent to the transfer of OPCo's generation assets and associated liabilities to AGR, AGR transferred at net book value a one-half interest (780 MW) in the Mitchell Plant to KPCo. The transfer of these generation assets and associated liabilities was approved by the FERC and the KPSC.

Other Impacts of Corporate Separation

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

Effective January 1, 2014, the FERC approved:

- PCA among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo will be individually responsible for planning their respective capacity obligations and there will be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

- Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance

Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

- Power Supply Agreement (PSA) between AGR and OPCo for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through auctions from January 1, 2014 through December 31, 2014.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

Our public utility subsidiaries' rates are regulated by the FERC and state regulatory commissions in our eleven state operating territories. The FERC also regulates our 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 our public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. For non-power goods and services, the FERC requires a nonregulated affiliate to bill an affiliated public utility company at no more than market while a public utility must bill the higher of cost or market to a nonregulated affiliate. The state regulatory commissions also regulate certain intercompany transactions under various orders and 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 and wholesale power transactions. Our wholesale power transactions are generally market-based. Wholesale power transactions are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. Our wholesale power transactions in the SPP region are currently cost-based within our balancing authority due to the FERC's finding that PSO and SWEPCo have market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. The state regulatory commissions also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of transitioning generation/power supply rates over time to market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by Texas Retail Electric Providers (REPs). Through our nonregulated subsidiaries, we enter into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. We have no active REPs in ERCOT.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia and I&M's retail transmission rates in Michigan are based on formula rates included in the PJM OATT that are cost-based. Although TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the PUCT. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions. Transmission rates for our seven wholly-owned transmission subsidiaries within our AEP

Transmission Holdco segment are based on formula rates included in the applicable RTO's OATT that are cost-based.

In addition, the FERC regulates the SIA, the Operating Agreement, the System Transmission Integration Agreement, the Transmission Agreement and the Transmission Coordination Agreement, all of which are still active and allocate shared system costs and revenues to the utility subsidiaries that are parties to each agreement. In accordance with management's December 2010 announcement and October 2012 filing with the FERC, the Interconnection Agreement was terminated effective January 1, 2014. The AEP System Interim Allowance

Agreement which provided for, among other things, the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement was also terminated. In December 2013, the FERC issued orders approving the creation of a PCA, effective January 1, 2014. Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent.

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and VIEs of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on the balance sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on the statements of income. We have ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and our proportionate share of the assets and liabilities are reflected on the balance sheets.

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our 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," we record 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 in conformity with GAAP 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, goodwill, intangible and 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 include temporary cash investments with original maturities of three months or less.

Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and Securities Available for Sale, including marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See “Fair Value Measurements of Other Temporary Investments” in Note 11.

Inventory

Fossil fuel inventories are generally carried at average cost with the exception of AGR and TNC which are carried at the lower of average cost or market. Materials and supplies inventories are carried at average cost.

Accounts Receivable

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

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled 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 I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo’s accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo’s West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables related to our risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For the wires business of TCC and TNC, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent, and for those balances less than 120 days where the collection is doubtful. 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.

Emission Allowances

In regulated jurisdictions, we record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. For our nonregulated business, we record allowances at the lower of cost or market. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on the balance sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on the statements of income at an average cost. We report the purchases and sales of allowances in the Operating Activities section of the statements of cash flows. We record the net margin on sales of emission allowances in Vertically Integrated Utilities Revenue on the statements of income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. 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 for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for our rate-regulated operations are stated at original cost. Additions, major replacements and betterments are added to the plant accounts. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in original cost retirements, less salvage, being charged to accumulated depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain our 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 held-for-sale 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. Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

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.

Nonregulated

Our nonregulated operations generally follow the policies of our rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. For nonregulated plant assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

For regulated operations, 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. We record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense. For nonregulated operations, including certain generating assets, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest."

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Accounts Payable and Short-term Debt approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

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

For our 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. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are nonbinding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations. If the points are highly correlated we include these locations 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 our contracts being classified as Level 3 is the inability to substantiate our energy price curves in the market. A significant portion of our Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in the benefit plan and nuclear trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. The trustee uses multiple pricing vendors for the assets held in the trusts.

Assets in the benefits and nuclear trusts, Cash and Cash Equivalents and Other Temporary Investments 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 Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current 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 state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a FAC under-recovery is no longer probable of recovery, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Ohio (beginning in 2012 through the ESP related to non-auction standard service offer load served) for OPCo, in Arkansas, Louisiana and Texas for SWEPCo, in Oklahoma for PSO and in Virginia and West Virginia (upon securitization in November 2013) for APCo are reflected in rates in a timely manner generally through the FAC. Changes in fuel costs, including purchased power in Ohio (beginning in 2009 through 2011) for OPCo and in West Virginia (prior to securitization in November 2013) for APCo are reflected in rates through FAC phase-in plans. The FAC generally includes some sharing of off-system sales. In West Virginia for APCo, all of the profits from off-system sales are given to customers through the FAC. None of the profits from off-system sales are given to customers through the FAC in Ohio for OPCo. A portion of profits from off-system sales are given to customers through the FAC and other rate mechanisms in Oklahoma for PSO, Arkansas, Louisiana and Texas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent, changes in fuel costs or sharing of off-system sales impact earnings.

Revenue Recognition

Regulatory Accounting

Our 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, we record them as assets on the balance sheets. We test 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, we write off that regulatory asset as a charge against income.

Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. For regulated and nonregulated operations, we recognize the revenues on the statements of income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants in the east service territory is sold to PJM. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as 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 Purchased Electricity for Resale on the statements of income. Other RTOs in which we participate 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 Purchased Electricity for Resale 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 Purchased Electricity for Resale on the statements of income. All other non-trading derivative purchases are recorded net in revenues.

In general, we record 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 where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale power, coal and natural gas marketing and risk management activities focused on wholesale markets where we own assets and adjacent markets. Our 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. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use 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. We include unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on the statements of income on a net basis. In jurisdictions subject to cost-based regulation, we defer unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on the balance sheets as Risk Management Assets or Liabilities as appropriate.

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). We initially record 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, we subsequently reclassify 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. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on the statements of income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Accounting for Cash Flow Hedging Strategies" section of Note 10.

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In accordance with regulatory orders, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. In certain regulatory jurisdictions, we defer costs above the level included in base rates and amortize those deferrals commensurate with recovery through rate riders.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes 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), we record deferred income taxes and establish related regulatory assets and liabilities to match the regulated revenues and tax expense.

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

We account for uncertain tax positions in accordance with the accounting guidance for "Income Taxes." We classify interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classify penalties as Other Operation expense.

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Debt

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Operations not subject to cost-based rate regulation report gains and losses on the reacquisition of debt in Interest Expense on the statements of income upon reacquisition.

We defer debt discount or premium and debt issuance expenses and amortize 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. We include the net amortization expense in Interest Expense on the statements of income.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

We have several trust funds with significant investments intended to provide for future payments of pension and OPEB benefits, nuclear decommissioning and spent nuclear fuel disposal. All of our trust funds' investments are diversified and managed in compliance with all laws and regulations. Our 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. We regularly review the actual asset allocations and periodically rebalance 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 our benefit plans support the allocation of assets to minimize risks and optimize net returns. Strategies used include:

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

The 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	30.0 %
Fixed Income	55.0 %
Other Investments	15.0 %

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 and prohibit the purchase of securities issued by AEP (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, our 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.

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- 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.

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. Our 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.

We participate 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. We lend 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.

We hold trust owned life insurance (TOLI) underwritten by The Prudential Insurance Company 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.

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the debt and equity investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the SNF disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

Stock-Based Compensation Plans

As of December 31, 2013, we had performance units and restricted stock units outstanding under the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by shareholders in April 2010. Upon vesting, performance units are paid in cash and restricted stock units are settled in AEP Common Shares, except for restricted stock units granted after January 1, 2013 and vesting to executive officers, which are paid in cash.

We maintain a variety of tax qualified and nonqualified deferred compensation plans for employees and non-employee directors that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of the Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and become payable to executives in cash after their service ends. Dividends paid on career shares are reinvested as additional career shares.

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

In January 2006, we adopted accounting guidance for "Compensation - Stock Compensation" which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees and directors, including stock options, based on estimated fair values.

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on the statements of income for the years ended December 31, 2013, 2012 and 2011 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2013, 2012 and 2011, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

Amounts Attributable to AEP Common Shareholders	Years Ended December 31, 2013	2012	2011
		(in millions)	
Income Before Extraordinary Item	$ 1,480	$ 1,259	$ 1,568
Extraordinary Item, Net of Tax	-	-	373
Earnings Attributable to AEP Common Shareholders	$ 1,480	$ 1,259	$ 1,941

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on the statements of income:

	Years Ended December 31, 2013		2012		2011	
	(in millions, except per share data)	$/share		$/share		$/share
Earnings Attributable to AEP Common Shareholders	$ 1,480		$ 1,259		$ 1,941	
Weighted Average Number of Basic Shares Outstanding	486.6	$ 3.04	484.7	$ 2.60	482.2	$ 4.02
Weighted Average Dilutive Effect of:						
Stock Options	-	-	-	-	0.1	-
Restricted Stock Units	0.4	-	0.4	-	0.2	-
Weighted Average Number of Diluted Shares Outstanding	487.0	$ 3.04	485.1	$ 2.60	482.5	$ 4.02

There were no antidilutive shares outstanding as of December 31, 2013, 2012 and 2011.

OPCo Revised Depreciation Rates

Effective December 1, 2011, we revised book depreciation rates for certain of OPCo's generation plants consistent with shortened depreciable lives for the generating units. This change in depreciable lives resulted in a $52 million increase in depreciation expense in 2012.

In the fourth quarter of 2012, we impaired certain Ohio generating units (see Note 7). As a result of this impairment of the full book value of these assets, we ceased depreciation on these generating units effective December 1, 2012.

In the second quarter of 2013, we impaired Muskingum River Plant, Unit 5 (MR5). As a result of this impairment of the full book value of this generating unit, we ceased depreciation on MR5 effective July 1, 2013.

Supplementary Related Party Information

AEP and several nonaffiliated utility companies jointly own OVEC. As of December 31, 2013, AEP's ownership and investment in OVEC were 43.47% and $4.4 million, respectively.

OVEC's owners are members to an intercompany power agreement. Participants of this agreement are entitled to receive and obligated to pay for all OVEC generating capacity, approximately 2,200 MWs, in proportion to their respective power participation ratios. The aggregate power participation ratio of certain AEP utility subsidiaries is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and provide a return on capital. In 2011, the intercompany power agreement was extended until June 2040.

AEP and other nonaffiliated owners authorized environmental investments related to their ownership interests and OVEC's Board of Directors authorized capital expenditures totaling $1.4 billion in connection with the engineering and construction of FGD projects and the associated waste disposal landfills at OVEC's two generation plants. These environmental projects were funded through debt issuances. As of December 31, 2013, both generation plants were operating with new environmental controls.

The following details related party transactions for the years ended December 31, 2013, 2012 and 2011:

Related Party Transactions	Years Ended December 31, 2013	2012	2011
		(in millions)	
AEP Consolidated Revenues – Other Revenues			
OVEC – Barging and Other Transportation Services	$ 21	$ 30	$ 37
AEP Consolidated Expenses – Purchased Electricity for Resale:			
OVEC	289	273	383 (a)

(a) The parties to the Interconnection Agreement purchased power from OVEC to serve retail sales in 2011. The total amount reported in 2011 includes $66 million related to this agreement.

Supplementary Cash Flow Information

Cash Flow Information	Years Ended December 31, 2013	2012	2011
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 882	$ 931	$ 900
Income Taxes	(55)	(82)	(118)
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	182	63	54
Construction Expenditures Included in Current Liabilities as of December 31,	492	439	380
Acquisition of Nuclear Fuel Included in Current Liabilities as of December 31,	-	35	1
Assumption of Liabilities Related to Acquisitions	-	56	-
Expected Reimbursement for Spent Nuclear Fuel Dry Cask Storage	4	30	-

2. EXTRAORDINARY ITEM

TCC Texas Restructuring

In February 2006, the PUCT issued an order that denied recovery of capacity auction true-up amounts. Based on the February 2006 PUCT order, TCC recorded the disallowance as a $421 million ($273 million, net of tax) extraordinary loss in the December 31, 2005 financial statements. In July 2011, the Supreme Court of Texas reversed the PUCT's February 2006 disallowance of capacity auction true-up amounts and remanded for reconsideration the treatment of certain tax balances under normalization rules. Based upon the Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance, TCC recorded a pretax gain of $421 million ($273 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

Following a remand proceeding, the PUCT allowed TCC to retain contested tax balances in full satisfaction of its true-up proceeding, including carrying charges. Based upon the PUCT order, TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) and the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Item, Net of Tax on the statements of income in 2011.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the year ended December 31, 2013. All amounts in the following table are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Year Ended December 31, 2013

	Cash Flow Hedges			Pension and OPEB		
	Commodity	Interest Rate and Foreign Currency	Securities Available for Sale	Amortization of Deferred Costs	Changes in Funded Status	Total
			(in millions)			
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ 4	$ 112	$ (415)	$ (337)
Change in Fair Value Recognized in AOCI	10	2	3	-	177	192
Amounts Reclassified from AOCI	(2)	5	-	22	-	25
Net Current Period Other Comprehensive Income	8	7	3	22	177	217
Pension and OPEB Adjustment Related to Mitchell Plant	-	-	-	-	5	5
Balance in AOCI as of December 31, 2013	$ -	$ (23)	$ 7	$ 134	$ (233)	$ (115)

Reclassifications from Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the year ended December 31, 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 8 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Year Ended December 31, 2013

Gains and Losses on Cash Flow Hedges	**Amount of (Gain) Loss Reclassified from AOCI (in millions)**
Commodity:	
Vertically Integrated Utilities Revenues	$ (1)
Generation & Marketing Revenues	(10)
Purchased Electricity for Resale	8
Property, Plant and Equipment	-
Regulatory Assets/(Liabilities), Net (a)	-
Subtotal - Commodity	(3)
Interest Rate and Foreign Currency:	
Interest Expense	7
Subtotal - Interest Rate and Foreign Currency	7
Reclassifications from AOCI, before Income Tax (Expense) Credit	4
Income Tax (Expense) Credit	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	3
Gains and Losses on Securities Available for Sale	
Interest Income	-
Interest Expense	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	-
Income Tax (Expense) Credit	-
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	-
Pension and OPEB	
Amortization of Prior Service Cost (Credit)	(21)
Amortization of Actuarial (Gains)/Losses	55
Reclassifications from AOCI, before Income Tax (Expense) Credit	34
Income Tax (Expense) Credit	12
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	22
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 25

Represents realized gains and losses subject to regulatory accounting treatment recorded as either

(a) current or noncurrent on the balance sheets.

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) 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 and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)
Changes in Fair Value Recognized in AOCI	(15)	(14)	(29)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Vertically Integrated Utilities Revenues	-	-	-
Generation & Marketing Revenues	(5)	-	(5)
Purchased Electricity for Resale	13	-	13
Other Operation Expense	-	-	-
Maintenance Expense	-	-	-
Interest Expense	-	4	4
Property, Plant and Equipment	-	-	-
Regulatory Assets (a)	2	-	2
Balance in AOCI as of December 31, 2012	$ (8)	$ (30)	$ (38)

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11
Changes in Fair Value Recognized in AOCI	(5)	(28)	(33)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Vertically Integrated Utilities Revenues	1	-	1
Generation & Marketing Revenues	(3)	-	(3)
Purchased Electricity for Resale	(2)	-	(2)
Other Operation Expense	(1)	-	(1)
Maintenance Expense	(1)	-	(1)
Interest Expense	-	4	4
Property, Plant and Equipment	(1)	-	(1)
Regulatory Assets (a)	2	-	2
Balance in AOCI as of December 31, 2011	$ (3)	$ (20)	$ (23)

Represents realized gains and losses subject to regulatory accounting treatment recorded as either

(a) current or noncurrent on the balance sheets.

The following table provides details of changes in unrealized gains and losses related to Securities Available for Sale and the reasons for changes for the year ended December 31, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Securities Available for Sale
Year Ended December 31, 2012

		(in millions)
Balance in AOCI as of December 31, 2011	$	2
Changes in Fair Value Recognized in AOCI		2
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income:		
Interest Income		-
Balance in AOCI as of December 31, 2012	$	4

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESP

The PUCO issued an order in March 2009 that modified and approved the ESP which established rates at the start of the April 2009 billing cycle through 2011. OPCo collected the 2009 annualized revenue increase over the last nine months of 2009. The order also provided a phase-in FAC, which was authorized to be recovered through a non-bypassable surcharge over the period 2012 through 2018. The PUCO's March 2009 order was appealed to the Supreme Court of Ohio, which issued an opinion and remanded certain issues back to the PUCO.

In October 2011, the PUCO issued an order in the remand proceeding. As a result, OPCo ceased collection of POLR billings in November 2011 and recorded a write-off in 2011 related to POLR collections for the period June 2011 through October 2011. In February 2012, the Ohio Consumers' Counsel (OCC) and the IEU filed appeals of that order with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which, if ordered, could reduce OPCo's net deferred fuel costs up to the total balance. As of December 31, 2013, OPCo's net deferred fuel balance was $445 million, excluding unrecognized equity carrying costs. In February 2014, the Supreme Court of Ohio affirmed the PUCO's decision and rejected all appeals filed by the OCC and the IEU. In February 2014, the IEU filed for reconsideration of the Supreme Court of Ohio decision.

In August 2012, the PUCO issued an order in a separate proceeding which implemented a Phase-In Recovery Rider (PIRR) to recover deferred fuel costs in rates beginning September 2012. The PUCO ruled that carrying charges should be calculated without an offset for accumulated deferred income taxes and that a long-term debt rate should be applied when collections begin. In November 2012, OPCo filed an appeal at the Supreme Court of Ohio related to the PUCO decision in the PIRR proceeding claiming a long-term debt rate modified the previously adjudicated 2009 – 2011 ESP order, which granted a weighted average cost of capital rate. In November 2012, the IEU and the OCC filed appeals regarding the PUCO decision in the PIRR proceeding. These appeals principally argued that the PUCO should have reduced the deferred fuel balance to reflect the prior "improper" collection of POLR revenues which could reduce OPCo's net deferred fuel balance up to the total balance. These intervenors' appeals also argued that carrying costs should be reduced due to an accumulated deferred income tax credit which, as of December 31, 2013, could reduce carrying costs by $31 million including $16 million of unrecognized equity carrying costs. A decision from the Supreme Court of Ohio is pending.

In January 2011, the PUCO issued an order on the 2009 SEET filing. The order gave consideration for a future commitment to invest $20 million to support the development of a large solar farm. In January 2013, the PUCO found there was not a need for the large solar farm. The PUCO noted that OPCo remains obligated to spend $20 million on this solar project or another project. In September 2013, a proposed second phase of OPCo's *gridSMART*® program was filed with the PUCO which included a proposed project to satisfy this PUCO directive. A decision from the PUCO is pending.

In July 2011, OPCo filed its 2010 SEET filing with the PUCO. In October 2013, the PUCO issued an order on the 2010 SEET filing that determined there were excessive earnings of $7 million, which were primarily offset against deferred fuel, as ordered. OPCo is required to file its 2011 SEET filing with the PUCO on a separate CSPCo and OPCo company basis. In November 2013, OPCo filed its 2011 and 2012 SEET filings with the PUCO. In February 2014, the PUCO staff filed testimony asserting that no significantly excessive earnings had occurred in 2011 for CSPCo or OPCo and that no significantly excessive earnings had occurred in 2012 for OPCo. In February 2014, OPCo entered into a stipulation agreement with the PUCO staff in which both parties agree that there were no significantly excessive earnings in 2011 for CSPCo or OPCo. A hearing at the PUCO related to the 2011 SEET filing is scheduled for February 2014. Management does not believe that there were significantly excessive earnings in 2011 for either CSPCo or OPCo or in either 2012 or 2013 for OPCo.

Management is unable to predict the outcome of the unresolved litigation discussed above. Depending on the rulings in these proceedings, it could reduce future net income and cash flows and impact financial condition.

June 2012 – May 2015 ESP Including Capacity Charge

In August 2012, the PUCO issued an order which adopted and modified a new ESP that establishes base generation rates through May 2015. This ruling was generally upheld in rehearing orders in January and March 2013.

In July 2012, the PUCO issued an order in a separate capacity proceeding which stated that OPCo must charge CRES providers the Reliability Pricing Model (RPM) price and authorized OPCo to defer a portion of its incurred capacity costs not recovered from CRES providers up to $188.88/MW day. The RPM price is approximately $33/MW day through May 2014 and $148/MW day from June 2014 through May 2015. In December 2012, various parties filed notices of appeal of the capacity costs decision with the Supreme Court of Ohio.

As part of the August 2012 ESP order, the PUCO established a non-bypassable Retail Stability Rider (RSR), effective September 2012. The RSR is being collected from customers at $3.50/MWh through May 2014 and will be collected at $4.00/MWh for the period June 2014 through May 2015, with $1.00/MWh applied to the recovery of deferred capacity costs. As of December 31, 2013, OPCo's incurred deferred capacity costs balance of $288 million, including debt carrying costs, was recorded in Regulatory Assets on the balance sheet.

In January and March 2013, the PUCO issued its Orders on Rehearing for the ESP which generally upheld its August 2012 order including the implementation of the RSR. The PUCO clarified that a final reconciliation of revenues and expenses would be permitted for any over- or under-recovery on several riders including fuel. In addition, the PUCO addressed certain issues around the energy auctions while other SSO issues related to the energy auctions were deferred to a separate docket related to the competitive bid process (CBP). In April and May 2013, OPCo and various intervenors filed appeals with the Supreme Court of Ohio challenging portions of the PUCO's ESP order, including the RSR.

In November 2013, the PUCO issued an order approving OPCo's CBP with modifications. The modifications include the delay of the energy auctions that were originally ordered in the ESP order. OPCo must conduct an energy-only auction for 10% of the SSO load with delivery beginning April 2014 through May 2015. The PUCO also ordered OPCo to conduct energy-only auctions for an additional 50% of the SSO load with delivery beginning November 2014 through May 2015 and for the remaining 40% of the SSO load for delivery from January 2015 through May 2015. OPCo will conduct energy and capacity auctions for its entire SSO load for delivery starting in June 2015. The PUCO also approved the unbundling of the FAC into fixed and energy-related components and an intervenor proposal to blend the $188.88/MW day capacity price in proportion to the percentage of energy planned to be auctioned. Additionally, the PUCO ordered that intervenor concerns related to the recovery of the fixed fuel costs through potentially both the FAC and the approved capacity charges be addressed in subsequent FAC proceedings. Management believes that these intervenor concerns are without merit. In December 2013, the PUCO granted applications for rehearing for further consideration filed by OPCo and intervenors. In January 2014, the PUCO denied all rehearing requests and agreed to issue a supplemental request for an independent auditor in the 2012-2013 FAC proceeding to separately examine the recovery of the fixed fuel costs, including OVEC.

If OPCo is ultimately not permitted to fully collect its ESP rates including the RSR, and its fixed fuel and deferred capacity costs, it could reduce future net income and cash flows and impact financial condition.

Proposed June 2015 – May 2018 ESP

In December 2013, OPCo filed an application with the PUCO to approve an ESP that includes proposed rate adjustments and the continuation and modification of certain existing riders, including the Distribution Investment Rider (DIR), effective June 2015 through May 2018. This filing is consistent with the PUCO's objective for a full transition from FAC and base generation rates to market. The proposal includes a recommended auction schedule, a return on common equity of 10.65% on capital costs for certain riders and estimates an average decrease in rates of 9% over the three-year term of the plan for customers who receive their RPM and energy auction-based generation through OPCo. Additionally, the application identifies OPCo's intention to submit a separate application to continue the RSR established in the June 2012 – May 2015 ESP in which the unrecovered portion of the deferred capacity costs will continue to be collected at the rate of $4.00/MWh until the balance of the capacity deferrals has been collected. Management intends to file this application in the first quarter of 2014.

Corporate Separation

In October 2012, the PUCO issued an order which approved the corporate separation of OPCo's generation assets including the transfer of OPCo's generation assets and associated generation liabilities at net book value to AGR. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR. In June 2013, the IEU filed an appeal with the Supreme Court of Ohio claiming the PUCO order approving the corporate separation was unlawful. A decision from the Supreme Court of Ohio is pending. In December 2013, the PUCO approved OPCo's application to amend the corporate separation plan by permitting OPCo to retain certain rights to purchase power from OVEC. The approval is subject to the condition that energy from the OVEC entitlements are sold into the day-ahead or real-time PJM energy markets, or on a forward basis through a bilateral arrangement. In December 2013, corporate separation of OPCo's generation assets was completed. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters.

Storm Damage Recovery Rider (SDRR)

In December 2012, OPCo submitted an application with the PUCO to establish initial SDRR rates. The SDRR seeks recovery of 2012 incremental storm distribution expenses over twelve months starting with the effective date of the SDRR as approved by the PUCO. In December 2013, a stipulation agreement was reached between OPCo, the PUCO staff and all intervenors except the OCC. The stipulation included a $6 million reduction in the amount of 2012 storm expenses to be recovered and for recovery of those expenses to take place over a 12-month period. The agreement also states that carrying charges using a long-term debt rate will be assessed from April 2013 until recovery begins, but no additional carrying charges will accrue during the actual recovery period. In December 2013, the OCC filed testimony opposing the stipulation. The testimony recommended the disallowance of approximately $18 million of the 2012 storm expenses and that the remaining 2012 storm expenses be offset by an additional $20 million that OPCo was ordered to spend on a solar project in OPCo's 2009 SEET filing. See the "2009-2011 ESP" section above. Hearings were held at the PUCO in January 2014 related to the settlement agreement and to address issues presented in the OCC's testimony. As of December

31, 2013, OPCo has deferred $56 million in Regulatory Assets on the balance sheet related to 2012 storm damage. If OPCo is not ultimately permitted to recover these storm costs, it could reduce future net income and cash flows and impact financial condition.

2009 Fuel Adjustment Clause Audit

In January 2012, the PUCO issued an order in OPCo's 2009 FAC that the remaining $65 million in proceeds from a 2008 coal contract settlement agreement be applied against OPCo's under-recovered fuel balance. In April 2012, on rehearing, the PUCO ordered that the settlement credit only needed to reflect the Ohio retail jurisdictional share of the gain not already flowed through the FAC with carrying charges. As a result, OPCo recorded a $30 million net favorable adjustment on the statement of income in 2012. The January 2012 PUCO order also stated that a consultant should be hired to review the coal reserve valuation and recommend whether any additional value should benefit ratepayers. Management is unable to predict the outcome of any future consultant recommendation regarding valuation of the coal reserve. If the PUCO ultimately determines that additional amounts should benefit ratepayers as a result of the consultant's review of the coal reserve valuation, it could reduce future net income and cash flows and impact financial condition.

In August 2012, intervenors filed an appeal with the Supreme Court of Ohio claiming the settlement credit ordered by the PUCO should have reflected the remaining gain not already flowed through the FAC with carrying charges, which, if ordered, would be $35 million plus carrying charges. If the Supreme Court of Ohio ultimately determines that additional amounts should benefit ratepayers, it could reduce future net income and cash flows and impact financial condition.

2010 and 2011 Fuel Adjustment Clause Audits

The PUCO-selected outside consultant issued its 2010 and 2011 FAC audit reports which included a recommendation that the PUCO reexamine the carrying costs on the deferred FAC balance and determine whether the carrying costs on the balance should be net of accumulated income taxes with the use of a weighted average cost of capital (WACC). The PUCO subsequently ruled in the PIRR proceeding that the fuel clause for these years was approved with a WACC carrying cost and that the carrying costs on the balance should not be net of accumulated income taxes. Hearings at the PUCO were held in November 2013. If the PUCO orders result in a reduction to the FAC deferral, it could reduce future net income and cash flows and impact financial condition. See the 2009-2011 ESP section of the "Ohio Electric Security Plan Filing" related to the PUCO order in the PIRR proceeding.

Ormet

Ormet, a large aluminum company, had a contract to purchase power from OPCo through 2018. In February 2013, Ormet filed Chapter 11 bankruptcy proceedings in the state of Delaware. In October 2013, Ormet announced that it was unable to emerge from bankruptcy and shut down operations effective immediately. Based upon previous PUCO rulings providing rate assistance to Ormet, the PUCO is expected to permit OPCo to recover unpaid Ormet amounts through the Economic Development Rider, except where recovery from ratepayers is limited to $20 million related to previously deferred payments from Ormet's October and November 2012 power bills. OPCo expects that any additional unpaid generation usage by Ormet will be recoverable as a regulatory asset through the Economic Development Rider (EDR). In February 2014, a stipulation agreement between OPCo and Ormet was filed with the PUCO. The stipulation recommends approval of OPCo's right to fully recover approximately $49 million of foregone revenues through the EDR which, as of December 31, 2013, is recorded in regulatory assets on the balance sheet. Also in February 2014, intervenor comments were filed objecting to full recovery of these forgone revenues.

In addition, in the 2009 – 2011 ESP proceeding, intervenors requested that OPCo be required to refund the Ormet-related revenues under a previous interim arrangement (effective from January 2009 through September 2009) and requested that the PUCO prevent OPCo from collecting Ormet-related revenues in the future. Through September 2009, the last month of the interim arrangement, OPCo had $64 million of deferred

FAC costs related to the interim arrangement, excluding $2 million of unrecognized equity carrying costs. The PUCO did not take any action on this request. The intervenors raised this issue again in response to OPCo's November 2009 filing to approve recovery of the deferral under the interim agreement.

To the extent amounts discussed above are not recoverable, it could reduce future net income and cash flows and impact financial condition.

Ohio IGCC Plant

In March 2005, OPCo filed an application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. As of December 31, 2013, OPCo has collected $24 million in pre-construction costs authorized in a June 2006 PUCO order. Intervenors have filed motions with the PUCO requesting that OPCo refund all collected pre-construction costs to Ohio ratepayers with interest.

Management cannot predict the outcome of this proceeding concerning the Ohio IGCC plant or what effect, if any, this proceeding could have on future net income and cash flows. However, if OPCo is required to refund pre-construction costs collected, it could reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

SWEPCo constructed the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which was placed into service in December 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and operates the facility. As of December 31, 2013, SWEPCo's share of incurred construction expenditures for the Turk Plant was approximately $1.758 billion. As of December 31, 2013, a pretax provision of $59 million has been recorded for costs incurred in excess of a Texas cost cap, resulting in total net capitalized expenditures of $1.699 billion.

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the SWEPCo Arkansas jurisdictional share of the Turk Plant (approximately 20%). Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. In June 2010, in response to an Arkansas Supreme Court decision, the APSC issued an order which reversed and set aside the previously granted CECPN. This Turk Plant output that is currently not subject to cost-based rate recovery and is being sold into the wholesale market.

The PUCT approved a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated $1.522 billion projected cash construction cost, excluding related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at $28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. The PUCT decision was upheld on appeal. See the "2012 Texas Base Rate Case" disclosure below for a discussion of a PUCT order on the Texas capital cost cap.

If SWEPCo cannot ultimately recover its investment and expenses related to the Turk Plant or transmission lines, it could reduce future net income and cash flows and impact financial condition.

2012 Texas Base Rate Case

In July 2012, SWEPCo filed a request with the PUCT to increase annual base rates by $83 million, primarily due to the Turk Plant, based upon an 11.25% return on common equity to be effective January 2013. The requested base rate increase included a return on and of the Texas jurisdictional share (approximately 33%) of the Turk Plant generation investment as of December 2011, total Turk Plant related estimated transmission investment costs and associated operation and maintenance costs. The filing also (a) increased depreciation expense due to the decrease in the average remaining life of the Welsh Plant to account for the change in the retirement date of the Welsh Plant, Unit 2 from 2040 to 2016 and (b) included a return on and of the Stall Unit as of December 2011 and associated operation and maintenance costs.

In October 2013, the PUCT issued an order affirming the prudence of the Turk Plant but determining that the Turk Plant Texas capital cost cap established in the Certificate of Convenience and Necessity (CCN) case discussed above (the Texas capital cost cap) also limited SWEPCo's recovery of AFUDC in addition to its recovery of cash construction costs. As a result of the determination that AFUDC was to be included in the cap, in the third quarter of 2013, SWEPCo recorded an additional pretax regulatory disallowance of $111 million. The order approved an annual rate increase of approximately $39 million based upon a return on common equity of 9.65%, including an unfavorable consolidated income tax adjustment of $5 million. As a result of this approval, SWEPCo retroactively applied the rate increase to the end of January 2013. The order also provided that there would be no disallowance to the existing book investment in the Stall Unit and that the Turk Plant related transmission line investment that was not in service at the end of the test year would be excluded from rate base. SWEPCo has since sought approval to recover this transmission investment through a Transmission Cost Recovery Rider in a filing made in December 2013. Additionally, the PUCT deferred consideration of the requested increase in depreciation expense related to the change in the 2016 retirement date of the Welsh Plant, Unit 2. As of December 31, 2013, the net book value of Welsh Plant, Unit 2 was $87 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, SWEPCo filed a motion for rehearing with the PUCT. In December 2013, the PUCT issued an order granting rehearing and reversed its decision on consolidated tax savings increasing SWEPCo's annual revenues by $5 million. In January 2014, the PUCT determined that AFUDC was excluded from the Turk Plant's Texas jurisdictional capital cost cap. As a result of these rulings, in the fourth quarter of 2013, SWEPCo reversed $114 million of previously recorded regulatory disallowances. These rulings also increased SWEPCo's previously approved annual base rates by a total of $13 million, which was also retroactively applied to the end of January 2013. The resulting annual base rate increase is approximately $52 million.

If SWEPCo cannot ultimately recover its Texas jurisdictional share of the investment and expenses related to the Welsh Plant, Unit 2 and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

2013 Texas Transmission Costs Recovery Factor Filing

In December 2013, SWEPCo filed an application to implement its initial transmission cost recovery factor (TCRF) requesting additional annual revenue of $10 million. The TCRF is designed to recover increases from the amounts included in SWEPCo's Texas retail base rates for transmission infrastructure improvement costs and wholesale transmission charges under a tariff approved by the FERC. SWEPCo's application included Turk Plant transmission-related costs. In January and February 2014, intervenors filed motions with the PUCT opposing SWEPCo's filing. In February 2014, an Administrative Law Judge issued an order requesting additional information from SWEPCo related to this filing. If the PUCT were to disallow any portion of the TCRF, it could reduce future net income and cash flows.

2012 Louisiana Formula Rate Filing

In 2012, SWEPCo initiated a proceeding to establish new formula base rates in Louisiana, including recovery of the Louisiana jurisdictional share (approximately 29%) of the Turk Plant. In February 2013, a settlement was filed and approved by the LPSC. The settlement increased Louisiana total rates by approximately $2 million annually, effective March 2013, which consisted of an increase in base rates of approximately $85 million annually offset by a decrease in fuel and other rates of approximately $83 million annually. The March 2013 base rates are based on a 10% return on common equity and cost recovery of the Louisiana jurisdictional share of the Turk Plant and Stall Unit, subject to refund based on the staff review of the cost of service and the prudency review of the Turk Plant. The settlement also provided that the LPSC will review base rates in 2014 and 2015 and that SWEPCo will recover non-fuel Turk Plant costs and a full weighted-average cost of capital return on the prudently incurred Turk Plant investment in jurisdictional rate base, effective January 2013. In May 2013, SWEPCo filed testimony in the prudence review of the Turk Plant. If the LPSC orders refunds based upon the pending staff review of the cost of service or the prudency review of the Turk Plant, it could reduce future net income and cash flows and impact financial condition.

Flint Creek Plant Environmental Controls

In February 2012, SWEPCo filed a petition with the APSC seeking a declaratory order to install environmental controls at the Flint Creek Plant to comply with the standards established by the CAA. The estimated cost of the project is $408 million, excluding AFUDC and company overheads. As a joint owner of the Flint Creek Plant, SWEPCo's portion of those costs is estimated at $204 million. In July 2013, the APSC approved the request to install environmental controls at the Flint Creek Plant.

APCo and WPCo Rate Matters

Plant Transfers

In October 2012, the AEP East Companies submitted several filings with the FERC regarding the transfer of certain generation plants within the AEP System. See the "Corporate Separation and Termination of Interconnection Agreement" section of FERC Rate Matters. In December 2012, APCo and WPCo filed requests with the Virginia SCC and the WVPSC for approval to transfer at net book value to APCo a two-thirds interest in Amos Plant, Unit 3 and a one-half interest in the Mitchell Plant, comprising 1,647 MW of generating capacity. In July 2013, the Virginia SCC approved the transfer of the two-thirds interest in the Amos Plant, Unit 3 to APCo, but directed that an amount equal to $83 million pretax be removed from the proposed transfer price. The Virginia jurisdictional share of the disallowance was approximately $39 million. The Virginia SCC also denied the proposed transfer of the one-half interest in the Mitchell Plant to APCo.

In December 2013, the WVPSC approved the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo but deferred a final decision related to the recovery of West Virginia's jurisdictional share of the $83 million pretax Virginia SCC disallowance until APCo's next West Virginia base rate case which APCo has agreed to file no later than June 2014. The West Virginia and FERC jurisdictional share of the potential disallowance is approximately $44 million pretax. Additionally, the WVPSC order also approved a rate surcharge for Amos Plant, Unit 3 effective January 2014 and deferred ruling on the transfer of the one-half interest in the Mitchell Plant to APCo. The surcharge was offset by an equal reduction in ENEC revenue with no overall change in total revenue.

In December 2013, the transfer of OPCo's two-thirds interest in the Amos Plant, Unit 3 to APCo was completed. As a result of the Virginia order, in the fourth quarter of 2013, APCo recorded a pretax regulatory disallowance of $39 million in Asset Impairments and Other Related Charges on the statement of income. Management continues to review its options related to the remaining one-half interest in the Mitchell Plant currently owned by AGR. If APCo and WPCo are not ultimately permitted to recover their Amos Plant, Unit 3 incurred costs in West Virginia and FERC, it could reduce future net income and cash flows and impact financial condition.

APCo IGCC Plant

As of December 31, 2013, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $10 million applicable to its Virginia jurisdiction. If the costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

2013 Virginia Environmental Rate Adjustment Clause (Environmental RAC) Filing

In March 2013, APCo filed with the Virginia SCC for approval of an environmental RAC to recover $39 million related to 2012 and 2011 environmental compliance costs, including carrying costs. In March 2013, the environmental RAC surcharge expired related to the collection of 2009 and 2010 environmental compliance costs. In November 2013, the Virginia SCC approved a settlement agreement which recommended approval of an environmental RAC to recover $38 million of the 2012 and 2011 environmental compliance costs, effective January 2014 for a one-year period. The order also states that APCo must file its next environmental RAC petition on or before May 1, 2015. As of December 31, 2013, APCo has deferred $28 million for the Virginia portion of unrecovered environmental RAC costs incurred in 2012 and 2011, excluding $10 million of unrecognized equity carrying costs.

2013 Virginia Generation Rate Adjustment Clause (Generation RAC)Filing

In March 2013, APCo filed with the Virginia SCC to increase its generation RAC revenues by $12 million for a total of $38 million to collect costs related to the Dresden Plant. In December 2013, the Virginia SCC approved a settlement agreement that included an increase in the generation RAC to $39 million. Per the approved settlement agreement, the generation RAC increase was effective in February 2014 for a period of one year at which time the component to collect an under-recovery of approximately $10 million will cease and the remaining annual $29 million revenue to recover on-going Dresden Plant costs will continue. As of December 31, 2013, APCo has deferred $6 million for the Virginia portion of unrecovered costs of the Dresden Plant, excluding $5 million of unrecognized equity carrying costs.

2013 Virginia Transmission Rate Adjustment Clause (Transmission RAC)

In December 2013, APCo filed with the Virginia SCC to increase its transmission RAC revenues by $50 million annually. The increase in the transmission RAC is expected to be effective May 2014. In February 2014, a hearing was held at the Virginia SCC in which a stipulation agreement between APCo and the Virginia SCC staff was submitted to the Virginia SCC that recommended approval to increase the transmission RAC revenues by $49 million annually, subject to true-up. The stipulation included the Virginia SCC staff's commitment to fully audit APCo's transmission RAC under-recoveries and report its findings and recommendations in testimony in APCo's next transmission RAC filing in 2015. As of December 31, 2013, APCo has deferred $47 million for the Virginia portion of unrecovered transmission RAC costs. If the Virginia SCC were to disallow any portion of the transmission RAC, it could reduce future net income and cash flows.

2013 West Virginia Expanded Net Energy Charge (ENEC) Filing

In March 2012, West Virginia passed securitization legislation which allowed the WVPSC to establish a regulatory framework for electric utilities to securitize certain deferred ENEC balances and other ENEC-related assets. In August 2013, the WVPSC approved a settlement that included (a) a $56 million reduction in ENEC revenues, offset by a $6 million annual increase in construction surcharges, effective September 2013 and subject to true-up, (b) an agreement to file a base case no later than June 2014 and (c) the deferral of $21 million from the ENEC recovery balance with the ability to include that amount in the ENEC recovery balance upon reaching certain coal inventory levels at the Amos Plant. In September 2013, the WVPSC approved a settlement agreement filed by APCo, WPCo and intervenors which authorized APCo to securitize $376 million, plus upfront financing costs, primarily related to the December 2011 under-recovered ENEC deferral balance. In November 2013, APCo issued $380 million of Securitization Bonds to securitize the under-recovered ENEC deferral balance, including $4 million of upfront financing costs, with a final maturity date of August 2031. APCo implemented a new securitization rider which was offset by an equal reduction in ENEC revenues, with no overall change in total revenues.

As of December 31, 2013, APCo's ENEC net over-recovery balance was $86 million, of which $107 million was recorded in Regulatory Liabilities and $21 million was recorded in Regulatory Assets on the balance sheet.

Virginia Storm Costs

In March 2013, due to the 2013 enactment of a Virginia law, APCo wrote off $30 million of previously deferred 2012 Virginia storm costs. The change in law affected the test years to be included in APCo's next biennial Virginia base rate filing in March 2014 and the determination of how these costs are treated in the Virginia jurisdictional biennial earnings test for 2012 and 2013. As of December 31, 2013, APCo has not deferred any Virginia storm costs incurred in 2012 or 2013 based on actual 2012 and estimated 2013 Virginia jurisdictional earnings. The 2012 and 2013 earnings test will be filed in the first quarter of 2014 as part of APCo's biennial Virginia base rate filing.

PSO Rate Matters

2014 Oklahoma Base Rate Case

In January 2014, PSO filed a request with the OCC to increase annual base rates by $38 million, based upon a 10.5% return on common equity. This revenue increase includes a proposed increase in depreciation rates of $29 million. In addition, the filing proposed recovery of advanced metering costs through a separate rider over a three-year deployment period requesting $7 million of revenues in year one, increasing to $28 million in year three. The filing also proposed expansion of an existing transmission rider currently recovered in base rates to include additional types of transmission costs that are expected to increase over the next several years.

Oklahoma Environmental Compliance Plan

In September 2012, PSO filed an environmental compliance plan with the OCC reflecting the retirement of Northeastern Station (NES), Unit 4 in 2016 and additional environmental controls on NES, Unit 3 to continue operations through 2026. As of December 31, 2013, the net book values of NES, Units 3 and 4 were $208 million and $106 million, respectively, before cost of removal, including materials and supplies inventory and CWIP. In August 2013, the OCC dismissed PSO's environmental compliance plan case without prejudice but will permit PSO to seek recovery in a future proceeding. PSO will address the environmental compliance plan issues in future regulatory proceedings when it seeks cost recovery of the plan. If PSO is ultimately not permitted to fully recover its net book value of NES, Units 3 and 4 and other environmental compliance costs, it could reduce future net income and cash flows and impact financial condition.

I&M Rate Matters

2011 Indiana Base Rate Case

In February 2013, the IURC issued an order that granted an $85 million annual increase in base rates based upon a return on common equity of 10.2%. In a March 2013 order, the IURC approved an adjustment which increased the authorized annual increase in base rates from $85 million to $92 million. In March 2013, the Indiana Office of Utility Consumer Counselor (OUCC) filed a request for reconsideration with the IURC, which was denied. Also in March 2013, the OUCC filed an appeal of the order with the Indiana Court of Appeals. In September 2013, the OUCC filed a brief on appeal that included objections to the inclusion of a prepaid pension asset in rate base, the use of an end-of-test-year amount for materials and supplies instead of a thirteen-month average and the application of an "outdated" capital structure. If any part of the IURC order is overturned by the Indiana Court of Appeals, it could reduce future net income and cash flows.

Cook Plant Life Cycle Management Project (LCM Project)

In April and May 2012, I&M filed a petition with the IURC and the MPSC, respectively, for approval of the LCM Project, which consists of a group of capital projects to ensure the safe and reliable operations of the Cook Plant through its licensed life (2034 for Unit 1 and 2037 for Unit 2). The estimated cost of the LCM Project is $1.2 billion to be incurred through 2018, excluding AFUDC. As of December 31, 2013, I&M has incurred costs of $380 million related to the LCM Project, including AFUDC.

In July 2013, the IURC approved I&M's proposed project with the exception of an estimated $23 million related to certain items that might accommodate a future potential power uprate which the IURC stated I&M could seek recovery of in a subsequent base rate case. I&M will recover approved costs through an LCM rider which will be determined in semi-annual proceedings. The IURC authorized deferral accounting for costs incurred related to certain projects effective January 2012 to the extent such costs are not reflected in rates. In October 2013, I&M filed an application with the IURC for LCM rider rates effective January 2014. In November 2013, the OUCC filed testimony identifying concerns related to the LCM rider that included the use of forecasted capital expenditures and the method used to calculate carrying charges. In December 2013, the IURC issued an interim order authorizing the implementation of LCM rider rates effective January 2014, subject to reconciliation upon the issuance of a final order by the IURC.

In January 2013, the MPSC approved a Certificate of Need (CON) for the LCM Project and authorized deferral accounting for costs incurred related to the approved projects effective January 2013 until these costs are included in rates. In February 2013, intervenors filed appeals with the Michigan Court of Appeals objecting to the issuance of the CON as well as the amount of the CON related to the LCM Project.

If I&M is not ultimately permitted to recover its LCM Project costs, it could reduce future net income and cash flows and impact financial condition.

Rockport Plant Clean Coal Technology Project (CCT Project)

In April 2013, I&M filed an application with the IURC seeking approval of a Certificate of Public Convenience and Necessity (CPCN) to retrofit both units of the Rockport Plant with a dry sorbent injection system. The estimated cost in the application was $285 million, excluding AFUDC, to be shared equally between I&M and AEGCo. The application requested deferral treatment of any unrecovered carrying costs incurred during construction and incremental post in-service depreciation expense and operation and maintenance expenses until such costs are recognized and recovered in a rider. I&M also requested cost recovery associated with the retrofit using the Clean Coal Technology Rider recovery mechanism.

In November 2013, the IURC approved a settlement agreement that included the approval of the CPCN with an updated estimated CCT Project cost of $258 million, excluding AFUDC, and the recovery of the Indiana jurisdictional share of I&M's ownership share. The settlement agreement specifies that 80% of the recoverable I&M direct ownership share of CCT Project costs will be recovered through a Federal Mandate Rider with the remaining 20% deferred until rates are established in a subsequent rate case. I&M's Indiana jurisdictional allocated share of the CCT Project costs received in the form of purchased power from AEGCo will be recovered in subsequent I&M rate cases. As of December 31, 2013, we have incurred costs of $109 million related to the CCT Project, including AFUDC.

Tanners Creek Plant, Units 1 - 4

In 2011, I&M announced that it would retire Tanners Creek Plant, Units 1-3 by June 2015 to comply with proposed environmental regulations. In September 2013, I&M announced that Tanners Creek Plant, Unit 4 would also be retired in mid-2015 rather than being converted from coal to natural gas. I&M is currently recovering depreciation and a return on the net book value of the Tanners Creek Plant in base rates and plans to seek recovery of all of the plant's retirement related costs in its next Indiana and Michigan base rate cases.

In December 2013, I&M filed an application with the MPSC seeking approval of revised depreciation rates for Rockport Plant, Unit 1 and Tanners Creek Plant due to the retirement of the Tanners Creek Plant in 2015. Upon the retirement of the Tanners Creek Plant, I&M proposes that the net book value of the Tanners Creek Plant will be recovered over the remaining life of the Rockport Plant. I&M requested to have the impact of these new depreciation rates incorporated into the rates set in its next rate case. The new depreciation rates result in a decrease in I&M's Michigan jurisdictional electric depreciation expense which I&M proposes to implement in the month following a MPSC order in the revised depreciation case.

As of December 31, 2013, the net book value of the Tanners Creek Plant was $341 million, before cost of removal, including materials and supplies inventory and CWIP. If I&M is ultimately not permitted to fully recover its net book value of the Tanners Creek Plant and its retirement-related costs, it could reduce future net income and cash flows and impact financial condition.

KPCo Rate Matters

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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of December 31, 2013, the net book value of Big Sandy Plant, Unit 2 was $249 million, before cost of removal, including materials and supplies inventory and CWIP. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace a portion of the capacity from Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo’s request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In November 2013, the KPSC denied the Attorney General's petition for rehearing. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase included cost recovery of the proposed transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order in the plant transfer case which modified and approved a settlement agreement that included the approval of the proposed transfer of the one-half interest in the Mitchell Plant to KPCo. The modified and approved settlement agreement also included KPCo's agreement to withdraw this base rate case request and file a base case proceeding no later than December 2014 with its current base rates to remain in effect until at least May 2015. In November 2013, KPCo withdrew this base rate request and the withdrawal was approved by the KPSC.

FERC Rate Matters

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 filings requested approval to transfer at net book value (NBV) approximately 9,200 MW of OPCo-owned generation assets and associated liabilities to AGR. The AEP East Companies also requested FERC approval to transfer at NBV two-thirds ownership (867 MW) in Amos Plant, Unit 3 to APCo and transfer the Mitchell Plant at NBV to APCo and KPCo in equal one-half interests (780 MW each) to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AGR, the transfers of the Amos Plant and Mitchell Plant to APCo and KPCo, respectively, and the merger of APCo and WPCo. In January 2014, the FERC dismissed an IEU petition for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AGR. Similar asset transfer filings were made at the KPSC, the Virginia SCC and the WVPSC. In December 2013, corporate separation of OPCo's generation assets was completed. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters.

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

In December 2013, the FERC issued orders approving the creation of the PCA, effective January 1, 2014, conditioned upon certain compliance filings which were filed with the FERC in January 2014. The PCA was established among APCo, I&M and KPCo with AEPSC as the agent to coordinate the participants' respective power supply resources. Under the PCA, APCo, I&M and KPCo would be individually responsible for planning their respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, APCo, I&M and KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities.

Also effective January 1, 2014, the FERC approved the creation of a Bridge Agreement among AGR, APCo, I&M, KPCo and OPCo with AEPSC as the agent. The Bridge Agreement is an interim arrangement to: (a) address the treatment of purchases and sales made by AEPSC on behalf of member companies that extend beyond termination of the Interconnection Agreement and (b) address how member companies will fulfill their existing obligations under the PJM Reliability Assurance Agreement through the 2014/2015 PJM planning year. Under the Bridge Agreement, AGR is committed to meet capacity obligations of member companies through May 31, 2015.

Additionally, FERC approval was sought for a Power Supply Agreement (PSA) between AGR and OPCo. This agreement provides for AGR to supply capacity for OPCo's switched (at $188.88/MW day) and non-switched retail load for the period January 1, 2014 through May 31, 2015 and to supply the energy needs of OPCo's non-switched retail load that is not acquired through an auction from January 1, 2014 through December 31, 2014. In December 2013, the FERC issued an order approving the PSA. The order conditioned the acceptance of the PSA on the revision of the agreement to reflect the PUCO's current and future underlying rates and rate structure. In January 2014, initial revisions to reflect current underlying rates and rate structure were filed at the FERC.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by orders from the Virginia SCC and the KPSC related to the proposed asset transfers and to position the company for the final stages of corporate separation. In December 2013, the FERC issued an order approving these additional filings. See the "Plant Transfers" section of APCo and WPCo Rate Matters and the "Plant Transfer" section of KPCo Rate Matters for a discussion of those orders.

If incurred costs are not ultimately recovered, it could reduce future net income and cash flows and impact financial condition.

5. EFFECTS OF REGULATION

Regulated Generating Units to be Retired Before or During 2016

The following regulated generating units are probable of abandonment. Accordingly, CWIP and Plant in Service has been reclassified as Other Property, Plant and Equipment on the balance sheet as of December 31, 2013. The following table summarizes the plant investment and cost of removal, currently being recovered, for each generating unit as of December 31, 2013.

Plant Name and Unit	Company	Gross Investment	Accumulated Depreciation	Net Investment	Cost of Removal Regulatory Liability	Expected Retirement Date	Remaining Recovery Period
			(in millions)				
Tanners Creek Plant, Units 1-4	I&M	$ 681	$ 354	$ 327	$ 87	2015	17 years
Big Sandy Plant, Unit 2	KPCo	424	180	244	47	2015	27 years
Northeastern Station, Unit 4	PSO	182	89	93	11	2016	27 years
Welsh Plant, Unit 2	SWEPCo	175	93	82	19	2016	27 years
Total		$ 1,462	$ 716	$ 746	$ 164		

In accordance with accounting guidance for "Regulated Operations", APCo regulated generating units expected to be retired before or during 2016 are not considered probable of abandonment.

Regulatory Assets

Regulatory assets are comprised of the following items:

	December 31, 2013	2012	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 61	$ 86	1 year
Under-recovered Fuel Costs - does not earn a return	19	2	1 year
Total Current Regulatory Assets	$ 80	$ 88	
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Storm Related Costs	$ 22	$ 23	
Ohio Economic Development Rider	14	13	
Other Regulatory Assets Not Yet Being Recovered	4	1	
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	161	172	
Ormet Special Rate Recovery Mechanism	36	5	
Indiana Under-Recovered Capacity Costs	22	-	
Expanded Net Energy Charge - Coal Inventory	21	-	
Mountaineer Carbon Capture and Storage Product Validation Facility	13	14	
Virginia Environmental Rate Adjustment Clause	2	29	
Litigation Settlement	-	11	
Other Regulatory Assets Not Yet Being Recovered	35	36	
Total Regulatory Assets Not Yet Being Recovered	330	304	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Ohio Fuel Adjustment Clause	445	519	5 years
Ohio Capacity Deferral	288	66	5 years
Ohio Transmission Cost Recovery Rider	87	49	2 years
Unamortized Loss on Reacquired Debt	81	82	30 years
Texas Meter Replacement Costs	77	47	15 years
Ohio Distribution Decoupling	31	-	2 years
Storm Related Costs	17	36	5 years
RTO Formation/Integration Costs	12	15	6 years
Red Rock Generating Facility	10	10	43 years
West Virginia Expanded Net Energy Charge	-	273	
Ohio Deferred Asset Recovery Rider	-	152	
Other Regulatory Assets Being Recovered	18	15	various
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	1,390	1,353	55 years

Pension and OPEB Funded Status	1,157	1,896	11 years
Cook Nuclear Plant Refueling Outage Levelization	58	27	3 years
Medicare Subsidy	51	-	11 years
Virginia Transmission Rate Adjustment Clause	47	33	2 years
Peak Demand Reduction/Energy Efficiency	44	12	2 years
Postemployment Benefits	40	45	5 years
United Mine Workers of America Pension Withdrawal	27	-	12 years
Virginia Environmental Rate Adjustment Clause	27	8	1 year
Under-Recovery of Transmission Cost Recovery Factor	20	6	1 year
Storm Related Costs	18	27	5 years
Vegetation Management	14	13	1 year
Deferred Restructuring Costs	11	15	5 years
Litigation Settlement	10	-	12 years
Under-Recovered Distribution Investment Rider	9	1	1 year
Asset Retirement Obligation	8	9	33 years
West Virginia Expanded Net Energy Charge	-	26	
Ohio Distribution Decoupling	-	16	
Deferred PJM Fees	-	14	
Unrealized Loss on Forward Commitments	-	8	
Other Regulatory Assets Being Recovered	49	29	various
Total Regulatory Assets Being Recovered	4,046	4,802	
Total Noncurrent Regulatory Assets	$ 4,376	$ 5,106	

Regulatory Liabilities

Regulatory liabilities are comprised of the following items:

	December 31, 2013	December 31, 2012	Remaining Refund Period
Current Regulatory Liabilities	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 9	$ 25	1 year
Over-recovered Fuel Costs - does not pay a return	110	22	1 year
Total Current Regulatory Liabilities	$ 119	$ 47	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Louisiana Refundable Construction Financing Costs	$ -	$ 96	
Other Regulatory Liabilities Not Yet Being Paid	5	4	
Regulatory Liabilities Currently Not Paying a Return			
Other Regulatory Liabilities Not Yet Being Paid	3	9	
Total Regulatory Liabilities Not Yet Being Paid	8	109	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,589	2,511	(a)
Louisiana Refundable Construction Financing Costs	78	-	5 years
Advanced Metering Infrastructure Surcharge	68	83	7 years
Deferred Investment Tax Credits	29	23	47 years
Excess Earnings	12	12	40 years
Other Regulatory Liabilities Being Paid	1	1	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability	597	436	(b)
Deferred Investment Tax Credits	121	136	49 years
Spent Nuclear Fuel Liability	43	43	(b)
Over-Recovery of Transition Charges	40	57	14 years
Unrealized Gain on Forward Commitments	35	46	4 years
Deferred State Income Tax Coal Credits	28	29	10 years
Peak Demand Reduction/Energy Efficiency	18	31	1 year
Over-Recovery of PJM Expense	14	-	2 years
Other Regulatory Liabilities Being Paid	13	27	various
Total Regulatory Liabilities Being Paid	3,686	3,435	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,694	$ 3,544	

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

We are subject to certain claims and legal actions arising in our ordinary course of business. In addition, our business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation against us 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 our financial statements.

COMMITMENTS

Construction and Commitments

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

The following table summarizes our actual contractual commitments as of December 31, 2013:

Contractual Commitments	Less Than 1 Year	2-3 Years	4-5 Years	After 5 Years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,387	$ 3,358	$ 2,189	$ 2,480	$ 10,414
Energy and Capacity Purchase Contracts	195	410	457	2,634	3,696
Construction Contracts for Capital Assets (b)	146	-	-	-	146
Total	$ 2,728	$ 3,768	$ 2,646	$ 5,114	$ 14,256

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents only capital assets for which we have 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

We record liabilities for guarantees in accordance with the accounting guidance for “Guarantees.” There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as natural gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two revolving credit facilities totaling $3.5 billion, under which we may issue up to $1.2 billion as letters of credit. As of December 31, 2013, the maximum future payments for letters of credit issued under the revolving credit facilities were $170 million with maturities ranging from February 2014 to April 2015.

In January 2014, we issued letters of credit utilizing the entire amount available under an $85 million uncommitted facility signed in October 2013. An uncommitted facility gives the issuer of the facility the right to accept or decline each request we make under the facility.

We have $352 million of variable rate Pollution Control Bonds supported by bilateral letters of credit for $356 million. The letters of credit have maturities ranging from March 2014 to March 2015. In February 2014, $106 million of bilateral letters of credit maturing in March 2014 were extended to March 2017.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of $115 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study completed in 2010, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. Actual reclamation costs could vary due to period inflation and any changes to actual mine reclamation. As of December 31, 2013, SWEPCo has collected approximately $62 million through a rider for final mine closure and reclamation costs, of which $16 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $46 million is recorded in Asset Retirement Obligations on the balance sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several 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, our exposure generally does not exceed the sale price. As of December 31, 2013, there were no material liabilities recorded for any indemnifications.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 13 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

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. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court's dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme

Court.

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. 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 filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

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, sludge, low-level radioactive waste and SNF. 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, our generation plants and transmission and distribution facilities have used asbestos, polychlorinated biphenyls and other hazardous and nonhazardous materials. We currently incur 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, 2013, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for five sites for which alleged liability is unresolved. There are eight additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at three sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our 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.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ. I&M's reserve is approximately $8 million. As the remediation work is completed, I&M's cost may change as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our 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 as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M site discussed above.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2012. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $1.3 billion to $1.7 billion in 2012 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amounts recovered in rates were $10 million, $14 million and $14 million for the years ended December 31, 2013, 2012 and 2011, respectively. Decommissioning costs recovered from customers are deposited in external trusts.

As of December 31, 2013 and 2012, the total decommissioning trust fund balance was $1.6 billion and $1.4 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income and cash flows would be reduced and financial condition could be impacted if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWh for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. As of December 31, 2013 and 2012, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $309 million and $308 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

In 2011, I&M signed a settlement agreement with the Federal government which permits I&M to make annual filings to recover certain SNF storage costs incurred as a result of the government's delays in accepting SNF for permanent storage. Under the settlement agreement, I&M received $31 million, $20 million and $14 million in 2013, 2012 and 2011, respectively, to recover costs and will be eligible to receive additional payment of annual claims for allowed costs that are incurred through December 31, 2016. The proceeds reduced costs for dry cask storage. As of December 31, 2013, I&M has deferred $22 million in Prepayments and Other Current Assets and $7 million in Deferred Charges and Other Noncurrent Assets on the balance sheet of dry cask storage and related operation and maintenance costs for recovery under this agreement.

See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for a nuclear incident at the Cook Plant for property damage, decommissioning and decontamination in the amount of $2.8 billion. Insurance coverage for a nonnuclear incident at the Cook Plant is $1.7 billion. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes industry mutual insurers for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $39 million for I&M which is assessable if the insurer's financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $13.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $121 million on each licensed reactor in the U.S. payable in annual installments of $19 million. As a result, I&M could be assessed $242 million per nuclear incident payable in annual installments of $38 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $13.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, it could reduce future net income and cash flows and impact financial condition.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

We maintain insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. Our insurance includes coverage for all risks of physical loss or damage to our nonnuclear 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. Our insurance programs also generally provide coverage against loss arising from certain claims made by third parties and are in excess of retentions absorbed by us. Coverage is generally provided by a combination of our protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

See “Nuclear Contingencies” section of this footnote for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. 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.

Rockport Plant Litigation

In July 2013, the Wilmington Trust Company filed a complaint in U.S. District Court for the Southern District of New York against AEGCo and I&M alleging that it will be unlawfully burdened by the terms of the modified NSR consent decree after the Rockport Plant, Unit 2 lease expiration in December 2022. The terms of the consent decree allow the installation of environmental emission control equipment, repowering or retirement of the unit. The plaintiff further alleges that the defendants’ actions constitute breach of the lease and participation agreement. The plaintiff seeks a judgment declaring that the defendants breached the lease, must satisfy obligations related to installation of emission control equipment and indemnify the plaintiff. The New York court has granted our motion to transfer this case to the U.S. District Court for the Southern District of Ohio. Our motion to dismiss, filed in October 2013, is pending. We will continue to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases.

We settled, received summary judgment or were dismissed from all of these cases. The plaintiffs appealed the Nevada federal district court's dismissal of several cases involving AEP companies to the U.S. Court of Appeals for the Ninth Circuit. In April 2013, the appellate court reversed in part, and affirmed in part, the district court's orders in these cases. The appellate court reversed the district court's holding that the state antitrust claims were preempted by the Natural Gas Act and the order dismissing AEP from two of the cases on personal jurisdiction grounds and affirmed the decision denying leave to the plaintiffs to amend their complaints in two of the cases. AEP filed a motion with the appellate court for rehearing on the issue of whether the district court had personal jurisdiction of AEP in the two referenced cases. No decision has been rendered on that motion. Defendants in these cases, including AEP, filed a petition seeking further review with the U.S. Supreme Court on the preemption issue, which is pending. We will continue to defend the cases. We believe the provision we have is adequate. We are unable to determine a range of potential losses that are reasonably possible of occurring.

7. ACQUISITIONS AND IMPAIRMENTS

ACQUISITIONS

2012

BlueStar Energy (Generation & Marketing segment)

In March 2012, we completed the acquisition of BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions for $70 million. This transaction also included goodwill of $15 million, intangible assets associated with sales contracts and customer accounts of $58 million and liabilities associated with supply contracts of $25 million. BlueStar has been in operation since 2002. Beginning in June 2012, BlueStar began doing business as AEP Energy. AEP Energy provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions throughout the United States, including demand response and energy efficiency services.

Other Matters

Enron Bankruptcy (Corporate and Other)

In February 2011, we reached a $425 million settlement covering all claims with BOA and Enron related to our purchase of Houston Pipeline Company (HPL) from Enron in 2001. As part of the settlement, we received title to the 55 billion cubic feet of natural gas in the Bammel storage facility and recorded this asset at fair value. Under the HPL sales agreement, we have a service obligation to the buyer for the right to use the cushion gas through May 2031. We recognized the obligation as a liability and will amortize it over the life of the agreement.

The settlement resulted in a pretax gain of $51 million and a net loss after tax of $22 million primarily due to an unrealized capital loss valuation allowance of $56 million.

IMPAIRMENTS

2013

Amos Plant, Unit 3 (Vertically Integrated Utilities segment)

In July 2013, the Virginia SCC approved the transfer of a two-thirds interest in the Amos Plant, Unit 3 to APCo but, for rate purposes, reduced the proposed transfer price by $83 million pretax. The Virginia jurisdictional share of the reduced price is approximately $39 million. In December 2013, the WVPSC issued an order that approved the transfer of a two-thirds interest in the Amos Plant, Unit 3 to APCo but deferred a final decision related to the $83 million pretax reduction in transfer price until APCo's next base rate case. The West Virginia and FERC jurisdictional share of the potential reduced transfer price is approximately $44 million. Upon evaluation, management believes the West Virginia jurisdictional share is probable of recovery. As a result of the Virginia order, in the fourth quarter of 2013, we recorded a pretax impairment of $39 million in Asset Impairments and Other Related Charges on the statement of income. See the "Plant Transfer" section of Note 4.

Big Sandy Plant, Unit 2 FGD Project (Vertically Integrated Utilities segment)

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million in Asset Impairments and Other Related Charges on the statement of income primarily related to the Big Sandy Plant, Unit 2 FGD project. See the "Plant Transfer" section of Note 4.

Muskingum River Plant, Unit 5 (Generation & Marketing segment)

In May 2013, the U.S. District Court for the Southern District of Ohio approved a modification to the consent decree, which was initially entered into in 2007, requiring certain types of pollution control equipment to be installed at certain AEP plants, including the 600 MW Muskingum River Plant, Unit 5 (MR5) coal-fired generation plant. Under the modification to the consent decree, we have the option to cease burning coal and retire MR5 in 2015 or to cease burning coal in 2015 and complete a natural gas refueling project no later than June 2017. In the second quarter of 2013, based on the approval of the modified consent decree and changes in other market factors, we re-evaluated potential courses of action with respect to the planned operation of MR5 and concluded that completion of a refueling project, which would have extended the useful life of MR5, is remote. As a result, management completed an impairment analysis and concluded that MR5 was impaired. Under a market-based value approach, using level 3 unobservable inputs, management determined that the fair value of this generating unit was zero based on the lack of installed environmental control equipment and the nature and condition of this generating unit. In the second quarter of 2013, we recorded a pretax impairment of $154 million in Asset Impairments and Other Related Charges on the statement of income which includes a $6 million pretax impairment of related material and supplies inventory. Management expects to retire the plant in 2015.

2012

Beckjord Plant, Unit 6, Conesville Plant, Unit 3, Kammer Plant, Units 1-3, Muskingum River Plant, Units 1-4, Sporn Plant, Units 2 and 4 and Picway Plant, Unit 5 (Generation & Marketing segment)

In October 2012, we filed applications with the FERC proposing to terminate the Interconnection Agreement and seeking to complete the corporate separation of OPCo's generation assets. Based on the intention to terminate the Interconnection Agreement and the FERC filing, we performed an evaluation of the recoverability of generation assets. As a result, in November 2012, we, using generating unit specific estimated future cash flows, concluded that we had a material impairment of certain Ohio generation assets. Under a market-based value approach, using level 3 unobservable inputs, we determined that the fair value of these generating units was zero based on the lack of installed environmental control equipment and the nature and condition of these generating units. In the fourth quarter of 2012, we recorded a pretax impairment of $287 million in Asset Impairments and Other Related Charges on the statement of income related to Beckjord Plant, Unit 6, Conesville Plant, Unit 3, Kammer Plant, Units 1-3, Muskingum River Plant, Units 1-4, Sporn Plant, Units 2 and 4 and Picway Plant, Unit 5 generating units which includes $13 million of related material and supplies inventory.

Turk Plant (Vertically Integrated Utilities segment)

In 2012, SWEPCo recorded a pretax write-off of $13 million in Asset Impairments and Other Related Charges on the statement of income related to unrecoverable construction costs subject to the Texas capital costs cap portion of the Turk Plant.

2011

Turk Plant (Vertically Integrated Utilities segment)

In the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Muskingum River Plant, Unit 5 FGD Project (MR5) (Generation & Marketing segment)

In September 2011, subsequent to the stipulation agreement filed with the PUCO, we determined that we were not likely to complete the previously suspended MR5 project and that the project's preliminary engineering costs were no longer probable of being recovered. As a result, in the third quarter of 2011, we recorded a pretax write-off of $42 million in Asset Impairments and Other Related Charges on the statement of income.

Sporn Plant, Unit 5 (Generation & Marketing segment)

In the third quarter of 2011, we decided to no longer offer the output of Sporn Plant, Unit 5 into the PJM Reliability Pricing Model auction. Sporn Plant, Unit 5 is not expected to operate in the future, resulting in the removal of Sporn Plant, Unit 5 from the Interconnection Agreement. As a result, in the third quarter of 2011, we recorded a pretax write-off of $48 million in Asset Impairments and Other Related Charges on the statement of income.

8. 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.

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide health and life insurance benefits for retired employees.

We recognize the funded status associated with our defined benefit pension and OPEB plans in the balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. We recognize an asset for a plan's overfunded status or a liability for a plan's underfunded status, and recognize, 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. We record a regulatory asset instead of other comprehensive income for qualifying benefit costs of our regulated operations that for ratemaking purposes are deferred for future recovery. The cumulative funded status adjustment is equal to the remaining unrecognized deferrals for unamortized actuarial losses or gains, prior service costs and transition obligations, such that remaining deferred costs result in an AOCI equity reduction or regulatory asset and deferred gains result in an AOCI equity addition or regulatory liability.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2013**	**2012**	**2013**	**2012**
Discount Rate	4.70 %	3.95 %	4.70 %	3.95 %
Rate of Compensation Increase	4.85 % (a)	4.95 % (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.

We use a duration-based method to determine the discount rate for our 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 2013, 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 4.85%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2013	**2012**	**2011**	**2013**	**2012**	**2011**
Discount Rate	3.95 %	4.55 %	5.05 %	3.95 %	4.75 %	5.25 %
Expected Return on Plan Assets	6.50 %	7.25 %	7.75 %	7.00 %	7.25 %	7.50 %
Rate of Compensation Increase	4.95 %	4.85 %	4.85 %	NA	NA	NA

NA Not applicable.

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

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

Health Care Trend Rates	2013	2012
Initial	6.75 %	7.00 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2020	2020

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 6	$ (4)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	74	(59)

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. We monitor the plans to control security diversification and ensure compliance with our investment policy. As of December 31, 2013, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2013 and 2012

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	
	2013	**2012**	**2013**	**2012**
Change in Benefit Obligation	(in millions)			
Benefit Obligation as of January 1,	$ 5,205	$ 4,991	$ 1,849	$ 2,227
Service Cost	69	76	23	47
Interest Cost	203	223	71	103
Actuarial (Gain) Loss	(305)	299	(395)	148
Plan Amendment Prior Service Credit	-	-	-	(570)
Curtailment and Settlements	-	(1)	-	-
Benefit Payments	(331)	(383)	(140)	(151)
Participant Contributions	-	-	39	35
Medicare Subsidy	-	-	9	10
Benefit Obligation as of December 31,	$ 4,841	$ 5,205	$ 1,456	$ 1,849
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets as of January 1,	$ 4,696	$ 4,303	$ 1,568	$ 1,410
Actual Gain on Plan Assets	340	560	208	178
Company Contributions	6	216	24	96
Participant Contributions	-	-	39	35
Benefit Payments	(331)	(383)	(140)	(151)
Fair Value of Plan Assets as of December 31,	$ 4,711	$ 4,696	$ 1,699	$ 1,568
Funded (Underfunded) Status as of December 31,	$ (130)	$ (509)	$ 243	$ (281)

Amounts Recognized on the Balance Sheets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	**2012**	**2013**	**2012**
	(in millions)			
Deferred Charges and Other Noncurrent Assets - Prepaid Benefit Costs	$ -	$ -	$ 264	$ -
Other Current Liabilities - Accrued Short-term Benefit Liability	(7)	(7)	(4)	(4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(123)	(502)	(17)	(277)
Funded (Underfunded) Status	$ (130)	$ (509)	$ 243	$ (281)

Amounts Included in AOCI and Regulatory Assets as of December 31, 2013 and 2012

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2013	2012	2013	2012
Components	(in millions)			
Net Actuarial Loss	$ 1,561	$ 2,111	$ 428	$ 989
Prior Service Cost (Credit)	8	11	(693)	(762)
Recorded as				
Regulatory Assets	$ 1,343	$ 1,774	$ (191)	$ 108
Deferred Income Taxes	79	122	(26)	42
Net of Tax AOCI	147	226	(48)	77

Components of the change in amounts included in AOCI and Regulatory Assets during the years ended December 31, 2013 and 2012 are as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2013	2012	2013	2012
Components	(in millions)			
Actuarial (Gain) Loss During the Year	$ (367)	$ 58	$ (496)	$ 67
Prior Service Credit	-	-	-	(570)
Amortization of Actuarial Loss	(183)	(155)	(65)	(57)
Amortization of Prior Service Credit (Cost)	(3)	1	69	18
Amortization of Transition Obligation	-	-	-	(1)
Change for the Year	$ (553)	$ (96)	$ (492)	$ (543)

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, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,092	$ -	$ -	$ -	$ 1,092	23.2 %
International	514	-	-	-	514	10.9 %
Real Estate Investment Trusts	58	-	-	-	58	1.2 %
Common Collective Trust - International	-	10	-	-	10	0.2 %
Subtotal - Equities	1,664	10	-	-	1,674	35.5 %
Fixed Income:						
Common Collective Trust - Debt	-	26	-	-	26	0.5 %
United States Government and Agency Securities	-	387	-	-	387	8.2 %
Corporate Debt	-	1,600	-	-	1,600	34.0 %
Foreign Debt	-	344	-	-	344	7.3 %
State and Local Government	-	28	-	-	28	0.6 %
Other - Asset Backed	-	33	-	-	33	0.7 %
Subtotal - Fixed Income	-	2,418	-	-	2,418	51.3 %
Real Estate	-	-	238	-	238	5.0 %
Alternative Investments	-	-	330	-	330	7.0 %
Securities Lending	-	35	-	-	35	0.8 %
Securities Lending Collateral (a)	-	-	-	(45)	(45)	(0.9)%
Cash and Cash Equivalents	-	48	-	-	48	1.0 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	13	13	0.3 %
Total	$ 1,664	$ 2,511	$ 568	$ (32)	$ 4,711	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:

	Real Estate	Alternative Investments	Total Level 3

Balance as of January 1, 2013	$	220	$	195	$	415
Actual Return on Plan Assets						
Relating to Assets Still Held as of the Reporting Date		26		15		41
Relating to Assets Sold During the Period		-		15		15
Purchases and Sales		(8)		105		97
Transfers into Level 3		-		-		-
Transfers out of Level 3		-		-		-
Balance as of December 31, 2013	$	238	$	330	$	568

The following table presents the classification of OPEB plan assets within the fair value hierarchy as of December 31, 2013:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 473	$ -	$ -	$ -	$ 473	27.9 %
International	616	-	-	-	616	36.2 %
Common Collective Trust - Global	-	15	-	-	15	0.9 %
Subtotal - Equities	1,089	15	-	-	1,104	65.0 %
Fixed Income:						
Common Collective Trust - Debt	-	88	-	-	88	5.2 %
United States Government and Agency Securities	-	56	-	-	56	3.3 %
Corporate Debt	-	110	-	-	110	6.5 %
Foreign Debt	-	22	-	-	22	1.2 %
State and Local Government	-	5	-	-	5	0.3 %
Other - Asset Backed	-	8	-	-	8	0.5 %
Subtotal - Fixed Income	-	289	-	-	289	17.0 %
Trust Owned Life Insurance:						
International Equities	-	13	-	-	13	0.8 %
United States Bonds	-	211	-	-	211	12.4 %
Cash and Cash Equivalents	68	9	-	-	77	4.5 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	5	5	0.3 %
Total	$ 1,157	$ 537	$ -	$ 5	$ 1,699	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, 2012:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,308	$ -	$ -	$ -	$ 1,308	27.9 %
International	497	-	-	-	497	10.5 %
Real Estate Investment Trusts	91	-	-	-	91	1.9 %
Common Collective Trust - International	-	4	-	-	4	0.1 %
Subtotal - Equities	1,896	4	-	-	1,900	40.4 %
Fixed Income:						
Common Collective Trust - Debt	-	32	-	-	32	0.7 %
United States Government and Agency Securities	-	715	-	-	715	15.2 %
Corporate Debt	-	1,235	-	-	1,235	26.3 %
Foreign Debt	-	199	-	-	199	4.2 %
State and Local Government	-	44	-	-	44	0.9 %
Other - Asset Backed	-	36	-	-	36	0.8 %
Subtotal - Fixed Income	-	2,261	-	-	2,261	48.1 %
Real Estate	-	-	220	-	220	4.7 %
Alternative Investments	-	-	195	-	195	4.2 %
Securities Lending	-	80	-	-	80	1.7 %
Securities Lending Collateral (a)	-	-	-	(91)	(91)	(1.9)%
Cash and Cash Equivalents	-	126	-	-	126	2.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	5	5	0.1 %
Total	$ 1,896	$ 2,471	$ 415	$ (86)	$ 4,696	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 millions)		
Balance as of January 1, 2012	$ 6	$ 163	$ 161	$ 330

Actual Return on Plan Assets				
Relating to Assets Still Held as of the Reporting Date	-	30	10	40
Relating to Assets Sold During the Period	(2)	-	4	2
Purchases and Sales	(4)	27	20	43
Transfers into Level 3	-	-	-	-
Transfers out of Level 3	-	-	-	-
Balance as of December 31, 2012	$ -	$ 220	$ 195	$ 415

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 millions)			
Equities:						
Domestic	$ 422	$ -	$ -	$ -	$ 422	26.9 %
International	505	-	-	-	505	32.2 %
Subtotal - Equities	927	-	-	-	927	59.1 %
Fixed Income:						
Common Collective Trust - Debt	-	72	-	-	72	4.6 %
United States Government and Agency Securities	-	82	-	-	82	5.2 %
Corporate Debt	-	155	-	-	155	9.9 %
Foreign Debt	-	26	-	-	26	1.7 %
State and Local Government	-	7	-	-	7	0.5 %
Other - Asset Backed	-	10	-	-	10	0.6 %
Subtotal - Fixed Income	-	352	-	-	352	22.5 %
Trust Owned Life Insurance:						
International Equities	-	52	-	-	52	3.3 %
United States Bonds	-	163	-	-	163	10.3 %
Cash and Cash Equivalents	62	11	-	-	73	4.7 %
Other - Pending Transactions and Accrued Income (a)	-	-	-	1	1	0.1 %
Total	$ 989	$ 578	$ -	$ 1	$ 1,568	100.0 %

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

Determination of Pension Expense

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

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

Accumulated Benefit Obligation	December 31, 2013	2012
	(in millions)	
Qualified Pension Plan	$ 4,638	$ 5,001
Nonqualified Pension Plans	77	82

Total	$ 4,715	$ 5,083

For our 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, 2013 and 2012 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2013	2012
	(in millions)	
Projected Benefit Obligation	$ 4,841	$ 5,205
Accumulated Benefit Obligation	$ 4,715	$ 5,083
Fair Value of Plan Assets	4,711	4,696
Underfunded Accumulated Benefit Obligation	$ (4)	$ (387)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $80 million and the OPEB plans of $6 million during 2014. For the pension plans, this amount includes the payment of unfunded nonqualified benefits plus contributions to the qualified trust fund of at least the minimum amount required by the Employee Retirement Income Security Act. For the qualified pension plan, we may also make additional discretionary contributions to maintain the funded status of the plan. For the OPEB plans, expected payments include the payment of unfunded benefits.

The table below reflects the total benefits expected to be paid from the plan or from our assets. The payments include the participants' contributions to the plan for their share of the cost. In November 2012, we announced changes to our retiree medical coverage. Effective for retirements after December 2012, our contribution to retiree medical coverage was capped reducing our exposure to future medical cost inflation. Effective for employees hired after December 2013, we will not provide retiree medical coverage. 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:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2014	$ 355	$ 140	$ -
2015	363	145	-
2016	368	149	-
2017	372	152	-
2018	377	156	-
Years 2019 to 2023, in Total	1,857	809	2

Components of Net Periodic Benefit Cost

The following table provides the components of our net periodic benefit cost (credit) for the plans for the years ended December 31, 2013, 2012 and 2011:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2013	2012	2011	2013	2012	2011
	(in millions)					
Service Cost	$ 69	$ 76	$ 72	$ 23	$ 47	$ 42
Interest Cost	203	223	237	71	103	109
Expected Return on Plan Assets	(278)	(319)	(314)	(107)	(101)	(109)
Curtailment	-	-	-	-	-	1
Amortization of Transition Obligation	-	-	-	-	1	2
Amortization of Prior Service Cost (Credit)	3	(1)	1	(69)	(18)	(1)
Amortization of Net Actuarial Loss	183	155	122	65	57	29
Net Periodic Benefit Cost (Credit)	180	134	118	(17)	89	73
Capitalized Portion	(56)	(42)	(37)	5	(28)	(22)
Net Periodic Benefit Cost (Credit) Recognized in Expense	$ 124	$ 92	$ 81	$ (12)	$ 61	$ 51

Estimated amounts expected to be amortized to net periodic benefit costs (credits) and the impact on the balance sheet during 2014 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 125	$ 21
Prior Service Cost (Credit)	2	(69)
Total Estimated 2014 Amortization	$ 127	$ (48)
Expected to be Recorded as		
Regulatory Asset	$ 107	$ (34)
Deferred Income Taxes	7	(5)
Net of Tax AOCI	13	(9)
Total	$ 127	$ (48)

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. 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 $67 million in 2013, $66 million in 2012 and $64 million in 2011.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by us and benefits are paid from our general assets.

The UMWA pension benefits are administered through a multiemployer plan that is different from single-employer plans as an employer's contributions may be used to provide benefits to employees of other participating employers. Required contributions not made by any employer may result in other employers bearing the unfunded plan obligations, while a withdrawing employer may be subject to a withdrawal liability. UMWA pension benefits are provided through the United Mine Workers of America 1974 Pension Plan (Employer Identification Number: 52-

1050282, Plan Number 002), which under the Pension Protection Act of 2006 (PPA) was in Seriously Endangered Status for the plan years ending June 30, 2013 and 2012, without utilization of extended amortization provisions. The Plan adopted a funding improvement plan in May 2012, as required under the PPA.

Contributions to the UMWA pension plan in 2013, 2012 and 2011 were made under a collective bargaining agreement that is scheduled to expire December 31, 2017. We contributed immaterial amounts in 2013, 2012 and 2011 that represent less than 5% of the total contributions in the plan's latest annual report for the years ended June 30, 2013, 2012 and 2011. The contributions we made did not include a surcharge. There are no minimum contributions for future years.

Based upon the plan to retrofit the Rockport Plant with dry sorbent injection technology to meet environmental emission control requirements, the timing of the closure of Cook Coal Terminal is expected to be in or after 2025. Due to the estimated closure date and the ability to estimate the amount of the withdrawal liability, we recorded a liability of $39 million during 2013 and a related regulatory asset of $30 million. The regulatory asset should be recovered in future billings for transloading services before the planned closure.

9. BUSINESS SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Vertically Integrated Utilities segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

During the fourth quarter of 2013, we changed the structure of our internal organization which resulted in a change in the composition of our reportable segments. In accordance with authoritative accounting guidance for segment reporting, prior period financial information has been recast in the financial statements and footnotes to be comparable to the current year presentation of reportable segments. See the "Corporate Separation" section of Executive Overview.

Our reportable segments and their related business activities are outlined below:

Vertically Integrated Utilities

- Generation, transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by AEGCo, APCo, I&M, KGPCo, KPCo, PSO, SWEPCo and WPCo.

Transmission and Distribution Utilities

- Transmission and distribution of electricity for sale to retail and wholesale customers through assets owned and operated by OPCo, TCC and TNC.
- OPCo purchases energy and capacity to serve remaining generation service customers.

Generation & Marketing

- Nonregulated generation in ERCOT and PJM.
- Marketing, risk management and retail activities in ERCOT, PJM and MISO.

AEP Transmission Holdco

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission only subsidiaries and transmission only joint ventures. These investments have PUCT-approved or FERC-approved returns on equity.

AEP River Operations

- Commercial barging operations that transports liquids, coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

The remainder of our activities is presented as Corporate and Other. While not considered a reportable segment, Corporate and Other primarily includes management and professional services to AEP provided at cost to AEP subsidiaries and the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.

The tables below present our reportable segment information for the years ended December 31, 2013, 2012 and 2011 and balance sheet information as of December 31, 2013 and 2012. These amounts include certain estimates and allocations where necessary.

	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments	C
				(in millions)				
Year Ended December 31, 2013								
Revenues from:								
External Customers	$ 9,347	$ 4,279	$ 27	$ 544	$ 1,208	$ 32	$ (80)(b)	$
Other Operating Segments	645	199	51	19	2,457	57	(3,428)	
Total Revenues	$ 9,992	$ 4,478	$ 78	$ 563	$ 3,665	$ 89	$ (3,508)	$
Asset Impairments and Other Related Charges	$ 72	$ -	$ -	$ -	$ 154	$ -	$ -	$
Depreciation and Amortization	941	591	10	31	236	-	(66)(c)	
Interest Income	7	2	-	-	2	69	(22)	
Carrying Costs Income	14	16	-	-	-	-	-	
Interest Expense	540	292	10	17	55	27	(35)(c)	
Income Tax Expense	398	198	29	7	112	(60)	-	
Net Income	681	358	80	12	228	125	-	

Gross Property Additions	1,822	871	843	7	185	9	(81)

Year Ended December 31, 2012	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments	C
				(in millions)				
Revenues from:								
External Customers	$ 8,785	$ 4,659	$ 7	$ 647	$ 882	$ 25	$ (60)(b)	$
Other Operating Segments	633	159	17	20	2,585	58	(3,472)	
Total Revenues	$ 9,418	$ 4,818	$ 24	$ 667	$ 3,467	$ 83	$ (3,532)	$
Asset Impairments and Other Related Charges	$ 13	$ -	$ -	$ -	$ 287	$ -	$ -	$
Depreciation and Amortization	873	561	3	29	349	-	(33)(c)	
Interest Income	5	4	-	-	1	22	(24)	
Carrying Costs Income	28	24	1	-	-	-	-	
Interest Expense	520	291	3	17	83	112	(38)(c)	
Income Tax Expense	345	201	17	7	15	19	-	
Net Income (Loss)	803	389	43	15	100	(88)	-	
Gross Property Additions	1,801	664	392	31	249	2	(20)	

Year Ended December 31, 2011	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments
				(in millions)			
Revenues from:							
External Customers	$ 8,942	$ 4,982	$ 3	$ 697	$ 563	$ 24	$ (95)(b)
Other Operating Segments	760	174	5	19	3,331	59	(4,348)
Total Revenues	$ 9,702	$ 5,156	$ 8	$ 716	$ 3,894	$ 83	$ (4,443)
Asset Impairments and Other Related Charges	$ 49	$ -	$ -	$ -	$ 90	$ -	$ -
Depreciation and Amortization	785	549	-	28	304	2	(13)(c)
Interest Income	13	7	-	-	4	22	(19)
Carrying Costs Income	17	376	-	-	-	-	-
Interest Expense	514	293	1	17	87	56	(35)(c)
Income Tax Expense	312	220	2	24	166	94	-
Income (Loss) Before Extraordinary Item	$ 710	$ 404	$ 30	$ 45	$ 439	$ (52)	$ -
Extraordinary Item, Net of Tax	-	373	-	-	-	-	-
Net Income (Loss)	$ 710	$ 777	$ 30	$ 45	$ 439	$ (52)	$ -
Gross Property Additions	$ 1,733	$ 544	$ 263	$ 18	$ 156	$ 219	$ (31)

(in millions)

December 31, 2013	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments (c)
Total Property, Plant and Equipment	$ 37,545	$ 12,143	$ 1,636	$ 638	$ 8,277	$ 315	$ (269)
Accumulated Depreciation and Amortization	12,250	3,342	10	189	3,409	173	(85)
Total Property, Plant and Equipment - Net	$ 25,295	$ 8,801	$ 1,626	$ 449	$ 4,868	$ 142	$ (184)
Total Assets	$ 32,791	$ 14,165	$ 2,245	$ 673	$ 6,426	$ 19,645	$ (19,531)(d)
Investments in Equity Method Investees	24	-	480	54	-	11	-

(in millions)

December 31, 2012	Vertically Integrated Utilities	Transmission and Distribution Utilities	AEP Transmission Holdco	AEP River Operations	Generation and Marketing	Corporate and Other (a)	Reconciling Adjustments (c)
Total Property, Plant and Equipment	$ 36,066	$ 11,461	$ 748	$ 636	$ 8,529	$ 280	$ (266)
Accumulated Depreciation and Amortization	11,733	3,232	4	161	3,465	168	(72)
Total Property, Plant and Equipment - Net	$ 24,333	$ 8,229	$ 744	$ 475	$ 5,064	$ 112	$ (194)
Total Assets	$ 32,008	$ 13,516	$ 1,216	$ 670	$ 6,664	$ 19,179	$ (18,886)(d)

Investments in Equity Method Investees	24	-	393	43	-	5	-

(a) Corporate and Other includes management and professional services to AEP provided at cost to AEP subsidiaries and the purchasing of receivables from certain AEP utility subsidiaries. This segment also includes parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
(b) Reconciling Adjustments for External Customers primarily include eliminations as a result of corporate separation.
(c) Includes eliminations due to an intercompany capital lease.
(d) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Risk Management Strategies

Our strategy surrounding the use of derivative instruments primarily focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. Our 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 we transact. To accomplish our objectives, we primarily employ 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.

We enter into power, coal, natural gas, interest rate and, to a lesser extent, heating oil, gasoline and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as "Interest Rate and Foreign Currency." The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors.

The following table represents the gross notional volume of our outstanding derivative contracts as of December 31, 2013 and 2012:

Notional Volume of Derivative Instruments

Primary Risk Exposure	Volume December 31, 2013	Volume December 31, 2012	Unit of Measure
	(in millions)		
Commodity:			
Power	406	498	MWhs
Coal	4	10	Tons
Natural Gas	127	147	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 191	$ 235	USD

Interest Rate and Foreign Currency	$	820	$	1,199	USD

Fair Value Hedging Strategies

We enter 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 our exposure to interest rate risk by converting a portion of our 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

We enter into and designate 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. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activities as "Commodity." We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to future borrowings of fixed-rate debt. Our 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. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we 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. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR 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 our derivative instruments, we also apply 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 our 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 our risk management contracts.

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2013 and 2012 balance sheets, we netted \$4 million and \$7 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and \$13 million and \$50 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 our derivative activity on the balance sheets as of December 31, 2013 and 2012:

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate and Foreign Currency (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in millions)			
Current Risk Management Assets	$ 347	$ 12	$ 4	$ 363	$ (203)	$ 160
Long-term Risk Management Assets	368	3	-	371	(74)	297
Total Assets	715	15	4	734	(277)	457
Current Risk Management Liabilities	292	11	1	304	(214)	90
Long-term Risk Management Liabilities	237	3	15	255	(78)	177
Total Liabilities	529	14	16	559	(292)	267
Total MTM Derivative Contract Net Assets (Liabilities)	$ 186	$ 1	$ (12)	$ 175	$ 15	$ 190

Fair Value of Derivative Instruments
December 31, 2012

	Risk Management Contracts	Hedging Contracts		Gross Amounts of Risk Management Assets/ Liabilities	Gross Amounts Offset in the Statement of Financial	Net Amounts of Assets/Liabilities Presented in the Statement of Financial
			Interest Rate and Foreign			

Balance Sheet Location	Commodity (a)	Commodity (a)	Currency (a)	Recognized	Position (b)	Position (c)
				(in millions)		
Current Risk Management Assets	$ 589	$ 32	$ 3	$ 624	$ (433)	$ 191
Long-term Risk Management Assets	528	5	1	534	(166)	368
Total Assets	1,117	37	4	1,158	(599)	559
Current Risk Management Liabilities	546	43	35	624	(469)	155
Long-term Risk Management Liabilities	383	6	6	395	(181)	214
Total Liabilities	929	49	41	1,019	(650)	369
Total MTM Derivative Contract Net Assets (Liabilities)	$ 188	$ (12)	$ (37)	$ 139	$ 51	$ 190

(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 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.

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

The table below presents our activity of derivative risk management contracts for the years ended December 31, 2013, 2012 and 2011:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2013	2012	2011
		(in millions)	
Vertically Integrated Utilities Revenues	$ 15	$ 10	$ 18
Generation & Marketing Revenues	49	50	48
Regulatory Assets (a)	(2)	(43)	(22)
Regulatory Liabilities (a)	(5)	8	(3)
Total Gain (Loss) on Risk Management Contracts	$ 57	$ 25	$ 41

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

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

Our 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, we designate a hedging instrument as a fair value hedge or a cash flow hedge.

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on the statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on the statements of income depending on the relevant facts and circumstances. However, unrealized and some realized gains and losses in regulated jurisdictions 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 impacts Net Income during the period of change.

We record 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 Expense on the statements of income. During 2013, we recognized a loss of $10 million on our hedging instruments and an offsetting gain of $10 million on our long-term debt. During 2012, the fair value changes for both our hedging instruments and hedged long-term debt were immaterial. During 2011, we recognized a gain of $3 million on our hedging instruments and an offsetting loss of $6 million on our long-term debt. For 2013, 2012 and 2011, hedge ineffectiveness was immaterial.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on the balance sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded 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 Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale 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 2013, 2012 and 2011, we designated power, coal and natural gas derivatives as cash flow hedges.

We reclassify gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the statements of income. During 2013, 2012 and 2011, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Interest Expense on the statements of income in those periods in which hedged interest payments occur. During 2013, 2012 and 2011, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on the balance sheets into Depreciation and Amortization expense on the statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2013, we did not designate any foreign currency derivatives as cash flow hedges. During 2012 and 2011, we designated foreign currency derivatives as cash flow hedges.

During 2013, 2012 and 2011, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2013, 2012 and 2011, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the balance sheets as of December 31, 2013 and 2012 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2013

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 7	$ -	$ 7
Hedging Liabilities (a)	6	2	8
AOCI Gain (Loss) Net of Tax	-	(23)	(23)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	-	(4)	(4)

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

Interest Rate

	Commodity	and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 24	$ -	$ 24
Hedging Liabilities (a)	36	37	73
AOCI Gain (Loss) Net of Tax	(8)	(30)	(38)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(8)	(4)	(12)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on the balance sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2013, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions was 44 months.

Credit Risk

We limit credit risk in our 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. We use Moody's, Standard and Poor's and current market-based qualitative and quantitative data as well as financial statements to assess the financial health of counterparties on an ongoing basis.

When we use standardized master agreements, these agreements may include collateral requirements. These master agreements facilitate the netting of cash flows associated with a single counterparty. Cash, letters of credit and parental/affiliate guarantees may be obtained as security from counterparties in order to mitigate credit risk. The collateral agreements require a counterparty to post cash or letters of credit in the event an exposure exceeds our established threshold. The threshold represents an unsecured credit limit which may be supported by a parental/affiliate guaranty, as determined in accordance with our 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 our competitive retail auction loads, we are obligated to post an additional amount of collateral if our credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and our total exposure. On an ongoing basis, our risk management organization assesses the appropriateness of these collateral triggering items in contracts. AEP and its subsidiaries have not experienced a downgrade below investment grade. The following table represents: (a) our fair value of such derivative contracts, (b) the amount of collateral we would have been required to post for all derivative and non-derivative contracts if our credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 3	$ 7
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	33	32
Amount Attributable to RTO and ISO Activities	28	31

In addition, a majority of our 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, our risk management organization assesses the appropriateness of these cross-default provisions in our 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 we have posted and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering our contractual netting arrangements as of

December 31, 2013 and 2012:

	December 31, 2013	December 31, 2012
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 293	$ 469
Amount of Cash Collateral Posted	1	8
Additional Settlement Liability if Cross Default Provision is Triggered	235	328

11. 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 we could realize in a current market exchange.

The book values and fair values of Long-term Debt as of December 31, 2013 and 2012 are summarized in the following table:

	December 31, 2013		December 31, 2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in millions)			
Long-term Debt	$ 18,377	$ 19,672	$ 17,757	$ 20,907

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include funds held by trustees primarily for the payment of securitization bonds and Securities Available for Sale, including marketable securities that we intend to hold for less than one year and investments by our protected cell of EIS. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2013			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 250	$ -	$ -	$ 250
Fixed Income Securities:				
Mutual Funds	80	-	-	80
Equity Securities - Mutual Funds	12	11	-	23
Total Other Temporary Investments	$ 342	$ 11	$ -	$ 353

	December 31, 2012			
Other Temporary Investments	Cost	Gross Unrealized Gains	Gross Unrealized Losses	Estimated Fair Value
	(in millions)			
Restricted Cash (a)	$ 241	$ -	$ -	$ 241
Fixed Income Securities:				
Mutual Funds	65	2	-	67
Equity Securities - Mutual Funds	10	6	-	16
Total Other Temporary Investments	$ 316	$ 8	$ -	$ 324

(a) Primarily represents amounts held for the repayment of debt.

The following table provides the activity for our fixed income and equity securities within Other Temporary Investments for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012 (in millions)	2011
Proceeds from Investment Sales	$ -	$ -	$ 268
Purchases of Investments	17	2	154
Gross Realized Gains on Investment Sales	-	-	4
Gross Realized Losses on Investment Sales	-	-	-

As of December 31, 2013 and 2012, we had no Other Temporary Investments with an unrealized loss position. As of December 31, 2013, fixed income securities were primarily debt based mutual funds with short and intermediate maturities. Mutual funds may be sold and do not contain maturity dates.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments as of December 31, 2013 and December 31, 2012:

	December 31, 2013			2012		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 19	$ -	$ -	$ 17	$ -	$ -
Fixed Income Securities:						
United States Government	609	26	(4)	648	58	(1)
Corporate Debt	37	2	(1)	35	5	(1)
State and Local Government	255	1	-	270	1	(1)
Subtotal Fixed Income Securities	901	29	(5)	953	64	(3)
Equity Securities - Domestic	1,012	506	(82)	736	285	(77)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,932	$ 535	$ (87)	$ 1,706	$ 349	$ (80)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2013, 2012 and 2011:

	Years Ended December 31, 2013	2012	2011

		(in millions)		
Proceeds from Investment Sales	$	858	$ 988	$ 1,111
Purchases of Investments		910	1,045	1,167
Gross Realized Gains on Investment Sales		18	25	33
Gross Realized Losses on Investment Sales		8	9	22

The adjusted cost of fixed income securities was $872 million and $889 million as of December 31, 2013 and 2012, respectively. The adjusted cost of equity securities was $506 million and $451 million as of December 31, 2013 and 2012, respectively.

The fair value of fixed income securities held in the nuclear trust funds, summarized by contractual maturities, as of December 31, 2013 was as follows:

	Fair Value of Fixed Income Securities
	(in millions)
Within 1 year	$ 79
1 year – 5 years	384
5 years – 10 years	188
After 10 years	250
Total	$ 901

Fair Value Measurements of Financial Assets and Liabilities

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

The following tables set forth, by level within the fair value hierarchy, our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2013 and 2012. 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. Our 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 our valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 16	$ 1	$ -	$ 101	$ 118
Other Temporary Investments					
Restricted Cash (a)	231	8	-	11	250
Fixed Income Securities:					
Mutual Funds	80	-	-	-	80
Equity Securities - Mutual Funds (b)	23	-	-	-	23
Total Other Temporary Investments	334	8	-	11	353
Risk Management Assets					
Risk Management Commodity Contracts (c) (d)	22	549	142	(273)	440
Cash Flow Hedges:					
Commodity Hedges (c)	-	15	-	(8)	7
Fair Value Hedges	-	1	-	3	4
De-designated Risk Management Contracts (e)	-	-	-	6	6
Total Risk Management Assets	22	565	142	(272)	457
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	8	-	-	11	19
Fixed Income Securities:					
United States Government	-	609	-	-	609
Corporate Debt	-	37	-	-	37
State and Local Government	-	255	-	-	255
Subtotal Fixed Income Securities	-	901	-	-	901
Equity Securities - Domestic (b)	1,012	-	-	-	1,012
Total Spent Nuclear Fuel and Decommissioning Trusts	1,020	901	-	11	1,932

Total Assets	$ 1,392	$ 1,475	$ 142	$ (149)	$ 2,860
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (d)	$ 30	$ 475	$ 22	$ (282)	$ 245
Cash Flow Hedges:					
Commodity Hedges (c)	-	11	3	(8)	6
Interest Rate/Foreign Currency Hedges	-	2	-	-	2
Fair Value Hedges	-	11	-	3	14
Total Risk Management Liabilities	$ 30	$ 499	$ 25	$ (287)	$ 267

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 6	$ 1	$ -	$ 272	$ 279
Other Temporary Investments					
Restricted Cash (a)	227	5	-	9	241
Fixed Income Securities:					
Mutual Funds	67	-	-	-	67
Equity Securities - Mutual Funds (b)	16	-	-	-	16
Total Other Temporary Investments	310	5	-	9	324
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	47	938	131	(599)	517
Cash Flow Hedges:					
Commodity Hedges (c)	8	28	-	(12)	24
Fair Value Hedges	-	2	-	2	4
De-designated Risk Management Contracts (e)	-	-	-	14	14
Total Risk Management Assets	55	968	131	(595)	559
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (f)	7	-	-	10	17
Fixed Income Securities:					
United States Government	-	648	-	-	648
Corporate Debt	-	35	-	-	35
State and Local Government	-	270	-	-	270
Subtotal Fixed Income Securities	-	953	-	-	953
Equity Securities - Domestic (b)	736	-	-	-	736
Total Spent Nuclear Fuel and Decommissioning Trusts	743	953	-	10	1,706
Total Assets	$ 1,114	$ 1,927	$ 131	$ (304)	$ 2,868
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 45	$ 838	$ 45	$ (636)	$ 292
Cash Flow Hedges:					
Commodity Hedges (c)	-	48	-	(12)	36
Interest Rate/Foreign Currency Hedges	-	37	-	-	37
Fair Value Hedges	-	2	-	2	4
Total Risk Management Liabilities	$ 45	$ 925	$ 45	$ (646)	$ 369

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 and Level 2 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

(c) 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."

(d) The December 31, 2013 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $4 million in 2014, $(11) million in periods 2015-2017 and $(1) million in periods 2018-2019; Level 2 matures $25 million in 2014, $37 million in periods 2015-2017, $7 million in periods 2018-2019 and $5 million in periods 2020-2030; Level 3 matures $27 million in 2014, $60 million in periods 2015-2017, $14 million in periods 2018-2019 and $19 million in periods 2020-2030. Risk management commodity contracts are substantially comprised of power contracts.

(e) 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.

(f) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(g) The December 31, 2012 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures $9 million in 2013, $(3) million in periods 2014-2016 and $(4) million in periods 2017-2018; Level 2 matures $16 million in 2013, $61 million in periods 2014-2016, $16 million in periods 2017-2018 and $7 million in periods 2019-2030; Level 3 matures $18 million in 2013, $31 million in periods 2014-2016, $13 million in periods 2017-2018 and $24 million in periods 2019-2030. Risk management commodity contracts are substantially comprised of power contracts.

There have been no transfers between Level 1 and Level 2 during the years ended December 31, 2013, 2012 and 2011.

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, 2013	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2012	$ 86
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(9)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	37
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	(3)
Purchases, Issuances and Settlements (c)	(16)
Transfers into Level 3 (d) (e)	19
Transfers out of Level 3 (e) (f)	(4)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	7
Balance as of December 31, 2013	$ 117

Year Ended December 31, 2012	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2011	$ 69
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(15)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	29
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	32
Transfers into Level 3 (d) (e)	1
Transfers out of Level 3 (e) (f)	(35)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	5
Balance as of December 31, 2012	$ 86

Year Ended December 31, 2011	Net Risk Management Assets (Liabilities) (in millions)
Balance as of December 31, 2010	$ 85
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(10)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	9
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(3)
Transfers into Level 3 (d) (e)	13
Transfers out of Level 3 (e) (f)	(12)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(13)
Balance as of December 31, 2011	$ 69

(a) Included in revenues on the 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 the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of our Level 3 positions as of December 31, 2013 and 2012:

Significant Unobservable Inputs
December 31, 2013

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High
	(in millions)					
Energy Contracts	$ 132	$ 22	Discounted Cash Flow	Forward Market Price (a)	$ 11.42	$ 120.72
				Counterparty Credit Risk (b)	316	
FTRs	10	3	Discounted Cash Flow	Forward Market Price (a)	(5.10)	10.44
Total	$ 142	$ 25				

Significant Unobservable Inputs
December 31, 2012

	Fair Value Assets	Fair Value Liabilities	Valuation Technique	Significant Unobservable Input	Input/Range Low	Input/Range High
	(in millions)					
Energy Contracts	$ 124	$ 38	Discounted Cash Flow	Forward Market Price (a)	$ 9.40	$ 111.97
				Counterparty Credit Risk (b)	397	
FTRs	7	7	Discounted Cash Flow	Forward Market Price (a)	(3.21)	14.79
Total	$ 131	$ 45				

(a) Represents market prices in dollars per MWh.
(b) Represents average price of credit default swaps used to calculate counterparty credit risk, reported in basis points.

12. INCOME TAXES

The details of our consolidated income taxes before extraordinary item as reported are as follows:

	Years Ended December 31, 2013	2012	2011
		(in millions)	
Federal:			
Current	$ (45)	$ (52)	$ 20
Deferred	676	698	786
Total Federal	631	646	806
State and Local:			
Current	29	35	37

Deferred	24	(77)	(25)
Total State and Local	53	(42)	12
Income Tax Expense	$ 684	$ 604	$ 818

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

	Years Ended December 31, 2013	2012	2011
	(in millions)		
Net Income	$ 1,484	$ 1,262	$ 1,949
Extraordinary Item, Net of Tax of $112 million in 2011	-	-	(373)
Income Before Extraordinary Item	1,484	1,262	1,576
Income Tax Expense	684	604	818
Pretax Income	$ 2,168	$ 1,866	$ 2,394
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 759	$ 653	$ 838
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	47	39	41
Investment Tax Credits, Net	(14)	(14)	(15)
Energy Production Credits	-	-	(18)
State and Local Income Taxes, Net	29	(33)	(22)
Removal Costs	(21)	(18)	(20)
AFUDC	(31)	(39)	(42)
Valuation Allowance	5	6	86
U.K. Windfall Tax	(80)	15	-
Other	(10)	(5)	(30)
Income Tax Expense	$ 684	$ 604	$ 818
Effective Income Tax Rate	31.5 %	32.4 %	34.2 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2013	2012
	(in millions)	
Deferred Tax Assets	$ 2,900	$ 2,900
Deferred Tax Liabilities	(13,088)	(12,098)
Net Deferred Tax Liabilities	$ (10,188)	$ (9,198)
Property Related Temporary Differences	$ (7,508)	$ (6,752)
Amounts Due from Customers for Future Federal Income Taxes	(273)	(289)
Deferred State Income Taxes	(765)	(683)
Securitized Assets	(870)	(780)
Regulatory Assets	(609)	(781)
Deferred Income Taxes on Other Comprehensive Loss	66	184
Accrued Nuclear Decommissioning	(554)	(475)
Net Operating Loss Carryforward	233	194

Tax Credit Carryforward	109	104
Valuation Allowance	(97)	(92)
All Other, Net	80	172
Net Deferred Tax Liabilities	$ (10,188)	$ (9,198)

AEP System Tax Allocation Agreement

We, along with our subsidiaries, file a consolidated federal income tax return. 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 our 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

We are no longer subject to U.S. federal examination for years before 2011. We 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 materially impact net income, cash flows or financial condition. The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. 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, we accrue interest on these uncertain tax positions. We are not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. However, it is possible that we have filed tax returns with positions that may be challenged by these tax authorities. We believe that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. We are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2009.

Net Income Tax Operating Loss Carryforward

In 2012 and 2011, we recognized federal net income tax operating losses of $366 million and $226 million, respectively, driven primarily by bonus depreciation, pension plan contributions and other book-versus-tax temporary differences. We also had state net income tax operating loss carryforwards as indicated in the table below.

State	State Net Income Tax Operating Loss Carryforward	Year of Expiration
	(in millions)	
Indiana	$ 50	2033
Louisiana	428	2028
Oklahoma	241	2033
Tennessee	9	2026
Virginia	301	2031
West Virginia	725	2032

As a result, we recognized deferred federal, state and local income tax benefits in 2012 and 2011. As of December 31, 2013, we have $156 million of unrealized federal net operating loss carryforward tax benefits. We anticipate future taxable income will be sufficient to realize the remaining net income tax operating loss tax benefits before the federal carryforward expires after 2032. We also anticipate future taxable income will be sufficient to realize the remaining state net income tax operating loss tax benefits before the state carryforward expires for each state.

At the end of 2013 and 2012, we had $121 million of uncertain tax positions netted against the federal net operating loss carryforward tax benefits.

Tax Credit Carryforward

Federal and state net income tax operating losses sustained in 2012, 2011 and 2009, along with lower federal and state taxable income in 2010, resulted in unused federal and state income tax credits. As of December 31, 2013, we have total federal tax credit carryforwards of $108 million and total state tax credit carryforwards of $98 million, not all of which are subject to an expiration date. If these credits are not utilized, the federal general business tax credits of $74 million will expire in the years 2028 through 2032 and the state coal tax credits of $29 million will expire in the years 2014 through 2022.

We anticipate future federal taxable income will be sufficient to realize the tax benefits of the federal tax credits before they expire unused. We do not anticipate state taxable income will be sufficient in future periods to realize the tax benefits of all state income tax credits before they expire and we have provided a valuation allowance accordingly.

Valuation Allowance

We assess past results and future operations to estimate and evaluate available positive and negative evidence to determine whether sufficient future taxable income will be generated to use existing deferred tax assets. A significant piece of objective negative information evaluated was the net income tax operating losses sustained in 2012, 2011 and 2009. The positive evidence we considered is the history of positive pretax income and the fact that the tax losses resulted from temporary differences that will reverse in future periods. On the basis of the evaluation of all available positive and negative evidence, as of December 31, 2013, a valuation allowance of $41 million for state tax credits, net of federal tax, and $56 million for an unrealized capital loss has been recorded in order to recognize only the portion of the deferred tax assets that, more likely than not, will be realized. The amount of the deferred tax assets realizable, however, could be adjusted if estimates of future taxable income during the carryforward period are materially impacted.

For a discussion of the tax implications of the unrealized capital loss resulting from our settlement with BOA and Enron, see “Enron Bankruptcy” section of Note 7.

Uncertain Tax Positions

In May 2013, the U.S. Supreme Court decided that the U.K. Windfall Tax imposed upon U.K. electric companies privatized between 1984 and 1996 is a creditable tax for U.S. federal income tax purposes. We filed protective claims asserting the creditability of the tax, dependent upon the outcome of the case. As a result of the favorable U.S. Supreme Court decision, we recognized a tax benefit of $80 million, plus $43 million of pretax interest income in the second quarter of 2013. The tax benefit and interest income resulted in an increase in net income of $108 million, but did not result in the receipt of cash in 2013.

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation expense 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,		
	2013	2012	2011
		(in millions)	
Interest Expense	$ 1	$ 11	$ 8
Interest Income	51	-	22
Reversal of Prior Period Interest Expense	-	1	13

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

	December 31,	
	2013	2012
	(in millions)	

Accrual for Receipt of Interest	$ 43	$ -
Accrual for Payment of Interest and Penalties	5	7

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

	2013	2012	2011
		(in millions)	
Balance as of January 1,	$ 267	$ 168	$ 219
Increase - Tax Positions Taken During a Prior Period	-	23	51
Decrease - Tax Positions Taken During a Prior Period	(94)	(16)	(43)
Increase - Tax Positions Taken During the Current Year	2	121	10
Decrease - Tax Positions Taken During the Current Year	-	-	-
Decrease - Settlements with Taxing Authorities	-	(25)	(31)
Decrease - Lapse of the Applicable Statute of Limitations	-	(4)	(38)
Balance as of December 31,	$ 175	$ 267	$ 168

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $87 million, $149 million and $111 million for 2013, 2012 and 2011, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

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 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 net income or financial condition but did have a favorable impact on cash flows in 2013.

Federal Tax Regulations

In 2013, the U.S. Treasury Department issued final and re-proposed regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. In addition, the IRS issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to net income, cash flows or financial condition.

State Tax Legislation

Legislation was passed by the state of Indiana in May 2011 enacting a phased reduction in corporate income tax rate from 8.5% to 6.5%. The 8.5% Indiana corporate income tax rate will be reduced 0.5% each year beginning after June 30, 2012 with the final reduction occurring in years beginning after June 30, 2015.

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

During the third quarter of 2013, it was determined that the state of West Virginia had achieved certain minimum levels of shortfall reserve funds. As a result, the West Virginia corporate income tax rate will be reduced from 7.0% to 6.5% in 2014. The enacted provisions will not materially impact net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for remaining periods up to 36 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 Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Additionally, for regulated operations with capital leases, a capital lease asset and offsetting liability are recorded at the present value of the remaining lease payments for each reporting period. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2013	2012	2011
		(in millions)	
Net Lease Expense on Operating Leases	$ 327	$ 346	$ 343
Amortization of Capital Leases	74	73	72
Interest on Capital Leases	28	29	32
Total Lease Rental Costs	$ 429	$ 448	$ 447

The following table shows the property, plant and equipment under capital leases and related obligations recorded on the balance sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on the balance sheets.

Property, Plant and Equipment Under Capital Leases	December 31, 2013	2012
	(in millions)	
Generation	$ 103	$ 117
Other Property, Plant and Equipment	627	495
Total Property, Plant and Equipment Under Capital Leases	730	612
Accumulated Amortization	197	173
Net Property, Plant and Equipment Under Capital Leases	$ 533	$ 439
Obligations Under Capital Leases		
Noncurrent Liability	$ 428	$ 375
Liability Due Within One Year	110	74
Total Obligations Under Capital Leases	$ 538	$ 449

Future minimum lease payments consisted of the following as of December 31, 2013:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2014	$ 135	$ 288
2015	111	268
2016	97	246
2017	79	230
2018	44	215

Later Years	215	862
Total Future Minimum Lease Payments	681	$ 2,109
Less Estimated Interest Element	143	
Estimated Present Value of Future Minimum Lease Payments	$ 538	

Master Lease Agreements

We lease 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, we are 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, 2013, the maximum potential loss for these lease agreements was approximately $20 million assuming the fair value of the equipment is zero at the end of the lease term.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant, Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. AEP, AEGCo and I&M have no ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2013 are as follows:

Future Minimum Lease Payments	**AEGCo**	**I&M**
	(in millions)	
2014	$ 74	$ 74
2015	74	74
2016	74	74
2017	74	74
2018	74	74
Later Years	295	295
Total Future Minimum Lease Payments	$ 665	$ 665

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $13 million and $15 million for I&M and SWEPCo, respectively, for the remaining railcars as of December 31, 2013. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 83% of the projected fair value of the equipment under the current five-year lease term to 77% at the end of the 20-year term. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. The maximum potential losses related to the guarantee are approximately $9 million and $10 million for I&M and SWEPCo, respectively, assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale-and-leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2013 and 2012 balance sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2013 and 2012 balance sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In November 2013, I&M entered into a sale-and-leaseback transaction with IMP 11-2013, a nonaffiliated Ohio Trust, to lease nuclear fuel for I&M's Cook Plant. In November 2013, I&M sold a portion of its unamortized nuclear fuel inventory to the trust for $110 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 54 months. The future payment obligations of $110 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2013 balance sheet. The future minimum lease payments for the sale-and-leaseback transaction as of December 31, 2013 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	**I&M (in millions)**
2014	$ 43
2015	32
2016	27
2017	6
2018	2
Total Future Minimum Lease Payments	$ 110

14. FINANCING ACTIVITIES

AEP Common Stock

Listed below is a reconciliation of common stock share activity for the years ended December 31, 2013, 2012 and 2011:

Shares of AEP Common Stock	**Issued**	**Held in Treasury**
Balance, December 31, 2010	501,114,881	20,307,725
Issued	2,644,579	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2011	503,759,460	20,336,592
Issued	2,245,502	-
Balance, December 31, 2012	506,004,962	20,336,592
Issued	2,109,002	-
Balance, December 31, 2013	508,113,964	20,336,592

Preferred Stock

In December 2011, AEP subsidiaries redeemed all of their outstanding preferred stock with a par value of $60 million at a premium, resulting in a $2.8 million loss, which is included in Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense on the statement of income.

Long-term Debt

The following details long-term debt outstanding as of December 31, 2013 and 2012:

Type of Debt and Maturity	Weighted Average Interest Rate as of December 31, 2013	Interest Rate Ranges as of December 31, 2013	Interest Rate Ranges as of December 31, 2012	Outstanding as of December 31, 2013	Outstanding as of December 31, 2012
				(in millions)	
Senior Unsecured Notes (a)					
2013-2043	5.45%	1.65%-8.13%	0.685%-8.13%	$ 11,799	$ 12,712
Pollution Control Bonds (b)					
2013-2038 (c)	3.29%	0.02%-6.30%	0.11%-6.30%	1,932	1,958
Notes Payable (d)					
2013-2032	4.17%	1.164%-8.03%	1.913%-8.03%	369	427
Securitization Bonds (e)					
2013-2031	3.72%	0.88%-6.25%	0.88%-6.25%	2,686	2,281
Spent Nuclear Fuel Obligation (f)				265	265
Other Long-term Debt (a) (g)					
2015-2059	1.41%	1.15%-13.718%	1.72%-13.718%	1,360	140
Fair Value of Interest Rate Hedges				(9)	3
Unamortized Discount, Net				(25)	(29)
Total Long-term Debt Outstanding				18,377	17,757
Long-term Debt Due Within One Year				1,549	2,171
Long-term Debt				$ 16,828	$ 15,586

(a) In July 2013, AGR, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. In 2013, OPCo borrowed $1 billion under the credit facility and retired other certain debt. On December 31, 2013, OPCo assigned the $1 billion in credit facility borrowings to AGR upon the transfer of OPCo's generation assets to AGR. Also on December 31, 2013, AGR subsequently assigned a portion of the borrowings to APCo and KPCo in the amounts of $300 million and $200 million, respectively, upon AGR's transfer of certain of those generation assets.

(b) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks and insurance policies support certain series.

(c) Certain pollution control bonds are subject to redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity purposes as Long-term Debt Due Within One Year on the balance sheets.

(d) Notes payable represent outstanding promissory notes issued under term loan agreements and credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(e) In 2013, APCo and OPCo issued $380 million and $267 million, respectively, of Securitization Bonds (see Note 16).

(f) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see "SNF Disposal" section of Note 6).

(g) In 2013, PSO, TCC and TNC issued $50 million, $100 million and $75 million three-year credit facilities, respectively, to be used for general corporate purposes.

Long-term debt outstanding as of December 31, 2013 is payable as follows:

	2014	**2015**	**2016**	**2017**	**2018**	**After 2018**	**Total**
				(in millions)			
Principal Amount	$ 1,549	$ 2,519	$ 1,147	$ 1,724	$ 1,135	$ 10,328	$ 18,402
Unamortized Discount, Net							(25)
Total Long-term Debt Outstanding							$ 18,377

In January 2014 and February 2014, I&M retired $5 million and $19 million, respectively, of Notes Payable related to DCC Fuel.

In January 2014, TCC retired $112 million of its outstanding Securitization Bonds.

In January 2014, OPCo retired $225 million of 4.85% Senior Unsecured Notes due in 2014.

As of December 31, 2013, trustees held, on our behalf, $500 million of our reacquired Pollution Control Bonds.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

Utility Subsidiaries' Restrictions

Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, several of our public utility subsidiaries have credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. As of December 31, 2013, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $6 billion.

The Federal Power Act prohibits the utility subsidiaries 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 the utility subsidiaries to pay dividends out of retained earnings.

Lines of Credit and Short-term Debt

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2013, we had credit facilities totaling $3.5 billion to support our commercial paper program. The maximum amount of commercial paper outstanding during 2013 was $904 million and the weighted average interest rate of commercial paper outstanding during 2013 was 0.32%. Our outstanding short-term debt was as follows:

	December 31,			
	2013		2012	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		**(in millions)**	
Securitized Debt for Receivables (b)	$ 700	0.23 %	$ 657	0.26 %
Commercial Paper	57	0.29 %	321	0.42 %
Line of Credit – Sabine (c)	-	- %	3	1.82 %
Total Short-term Debt	$ 757		$ 981	

(a) Weighted average rate.
(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance.
(c) This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

For a discussion of credit facilities, see “Letters of Credit” section of Note 6.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies’ receivables and accelerate AEP Credit’s cash collections.

In June 2013, we amended our receivables securitization agreement to extend through June 2014. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. We amended a commitment of $385 million to now expire in June 2014. The remaining commitment of $315 million expires in June 2015. We intend to extend or replace the agreement expiring in June 2014 on or before its maturity.

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2013	2012	2011
	(dollars in millions)		
Effective Interest Rates on Securitization of Accounts Receivable	0.23 %	0.26 %	0.27 %
Net Uncollectible Accounts Receivable Written Off	$ 35	$ 29	$ 37

	December 31,	
	2013	2012
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 929	$ 835
Total Principal Outstanding	700	657
Delinquent Securitized Accounts Receivable	45	37
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	16	21
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	331	316

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

15. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards to employees. A maximum of 10,000,000 shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. As of December 31, 2013, 15,973,699 shares remained available for issuance under the LTIP plan. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2013, 2012 or 2011 but we did have outstanding stock options from grants in earlier periods that were exercised in these years. As of December 31, 2013 we have no outstanding stock options. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1 of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total intrinsic value of options exercised is as follows:

Stock Options	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Intrinsic Value of Options Exercised (a)	$ 3,105	$ 1,699	$ 1,202

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2013, 2012 and 2011 is as follows:

	2013		2012		2011	
	Options	**Weighted Average Exercise Price**	**Options**	**Weighted Average Exercise Price**	**Options**	**Weighted Average Exercise Price**
	(in thousands)		**(in thousands)**		**(in thousands)**	
Outstanding as of January 1,	188	$ 30.17	321	$ 29.35	551	$ 32.88
Granted	-	NA	-	NA	-	NA
Exercised/Converted	(187)	30.18	(128)	28.21	(104)	27.39
Forfeited/Expired	(1)	27.95	(5)	27.26	(126)	46.40
Outstanding as of December 31,	-	NA	188	30.17	321	29.35
Options Exercisable as of December 31,	-	$ NA	188	$ 30.17	321	$ 29.35

NA Not applicable.

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a fair value upon vesting equal to the average closing market price of AEP common stock for the last 20 trading days of the performance period. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score can range from 0% to 200% and is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee. Performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that has a value equivalent to shares of AEP common stock. AEP Career Shares are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. We record compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on the balance sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2013, 2012 and 2011 as follows:

	Years Ended December 31,		
Performance Units	**2013**	**2012**	**2011**
Awarded Units (in thousands)	1,284	546	7

Weighted Average Unit Fair Value at Grant Date	$ 46.23	$ 41.38	$ 38.39
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	**Years Ended December 31, 2013**	**2012**	**2011**
Awarded Units (in thousands)	101	138	198
Weighted Average Grant Date Fair Value	$ 45.42	$ 40.97	$ 37.31
Vesting Period (in years)	(a)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant but are not paid in cash until after the participant's termination of employment.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the number of performance units earned but may not increase the number earned. The performance scores for all open performance periods prior to those granted in 2012 are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the electric utility and multi utility sub-industry segments of the Standard and Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target. Starting with the performance units granted in 2012, the three-year total shareholder return peer group was changed to the S&P 500 Electric Utility Index.

The certified performance scores and units earned for the three-year periods ended December 31, 2013, 2012 and 2011 were as follows:

Performance Units	Years Ended December 31, 2013	2012	2011
Certified Performance Score	118.8 %	99.7 %	89.8 %
Performance Units Earned	749,219	1,096,572	1,216,926
Performance Units Mandatorily Deferred as AEP Career Shares	72,883	51,056	52,639
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	39,691	26,337	42,502
Performance Units to be Paid in Cash	636,645	1,019,179	1,121,785

The cash payouts for the years ended December 31, 2013, 2012 and 2011 were as follows:

Performance Units and AEP Career Shares	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Cash Payouts for Performance Units	$ 43,925	$ 44,968	$ 15,985
Cash Payouts for AEP Career Share Distributions	3,675	11,027	2,777

Restricted Shares and Restricted Stock Units

In 2004, the independent members of the AEP Board of Directors granted restricted shares to the then Chairman, President and CEO upon the commencement of his AEP employment. The final 66,667 shares vested on November 30, 2011. Compensation cost for restricted shares is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of shares granted by the grant date market closing price, which was $30.76. The maximum contractual term for these restricted shares was eight years and dividends on these restricted shares were paid in cash. AEP has not granted other restricted shares.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments. Additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. Upon vesting, RSUs are converted into a share of AEP common stock, with the exception of participants subject to the disclosure requirements set forth in Section 16 of the Securities Exchange Act of 1934, who are paid in cash. For awards that are settled with shares, compensation cost is measured at fair value on the grant date and recorded over the vesting period. Fair value is determined by multiplying the number of units granted by the grant date market closing price. For awards that are paid in cash, compensation cost is recorded over the vesting period and adjusted for changes in value until vested. The fair value at vesting is determined by multiplying the number of units vested by the 20-day average closing price of AEP common stock. The maximum contractual term of outstanding RSUs is six years from the grant date.

In 2010, the HR Committee granted a total of 165,520 RSUs to four CEO succession candidates as a retention incentive for these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015. Of these RSUs, 55,172 vested on August 3, 2013 and 110,348 remain outstanding, excluding dividends.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2013, 2012 and 2011 as follows:

Restricted Stock Units	Years Ended December 31, 2013	2012	2011
Awarded Units (in thousands)	644	497	121
Weighted Average Grant Date Fair Value	$ 46.24	$ 40.69	$ 37.07

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2013, 2012 and 2011 were as follows:

Restricted Shares and Restricted Stock Units	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 15,325	$ 10,608	$ 7,164
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	20,378	12,157	8,017

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of our nonvested RSUs as of December 31, 2013 and changes during the year ended December 31, 2013 are as follows:

Nonvested Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested as of January 1, 2013	1,000	$ 38.22
Granted	644	46.24
Vested	(408)	37.57
Forfeited	(31)	39.97
Nonvested as of December 31, 2013	1,205	42.64

The total aggregate intrinsic value of nonvested RSUs as of December 31, 2013 was $56 million and the weighted average remaining contractual life was 2.09 years.

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. The number of stock units provided is based on the closing price of AEP common stock on the last trading day of the quarter for which the stock units were earned. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The stock units granted to Non-employee Directors are fully vested upon grant date. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the last 20 trading days prior to the distribution date.

We record compensation cost for stock units when the units are awarded and adjust the liability for changes in value based on the current 20-day average closing price of AEP common stock on the valuation date.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2013, 2012 and

2011.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2013, 2012 and 2011 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2013	2012	2011
Awarded Units (in thousands)	33	52	52
Weighted Average Grant Date Fair Value	$ 45.81	$ 41.20	$ 37.72

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2013, 2012 and 2011 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 56,352	$ 51,767	$ 61,807
Actual Tax Benefit Realized	19,723	18,119	12,632
Total Compensation Cost Capitalized	13,165	10,707	11,608

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on the statements of income.

During the years ended December 31, 2013, 2012 and 2011, there were no significant modifications affecting any of our share-based payment arrangements.

As of December 31, 2013, there was $105 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. Our unrecognized compensation cost will be recognized over a weighted-average period of 1.66 years.

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2013, 2012 and 2011 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2013	2012	2011
	(in thousands)		
Cash Received from Stock Options Exercised	$ 5,659	$ 3,598	$ 2,855
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	1,040	618	411

Our practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although we do not currently anticipate any changes to this practice, we are permitted to use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset our tax withholding obligation.

16. VARIABLE INTEREST ENTITIES

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE, variable interests held by related parties and other factors. We believe that significant assumptions and judgments were applied consistently.

We are the primary beneficiary of Sabine, DCC Fuel, AEP Credit, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and a protected cell of EIS. In addition, we have not provided material financial or other support to Sabine, DCC Fuel, AEP Credit, Transition Funding, Ohio Phase-in-Recovery Funding, Appalachian Consumer Rate Relief Funding and our protected cell of EIS that was not previously contractually required. We hold a significant variable interest in DHLC and Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series).

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2013, 2012 and 2011 were $155 million, $147 million and $128 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on the balance sheets.

I&M has nuclear fuel lease agreements with DCC Fuel II LLC, DCC Fuel IV LLC, DCC Fuel V LLC and DCC Fuel VI LLC (collectively DCC Fuel). DCC Fuel was formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. Each is a separate legal entity from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the leases for the years ended December 31, 2013, 2012 and 2011 were $153 million, $127 million and $85 million, respectively. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the respective lease terms, which do not exceed 54 months. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. In October 2013, the lease agreements ended for DCC Fuel LLC and DCC Fuel III LLC. See the tables below for the classification of DCC Fuel's assets and liabilities on the balance sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management concluded that we are the primary beneficiary and are required to consolidate AEP Credit. See the tables below for the classification of AEP Credit's assets and liabilities on the balance sheets. See "Securitized Accounts Receivables – AEP Credit" section of Note 14.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas Restructuring Legislation. Management has concluded that TCC is the primary beneficiary of Transition Funding because TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $2 billion and $2.3 billion as of December 31, 2013 and 2012, respectively. Transition Funding has securitized transition assets of $1.9 billion and $2.1 billion as of December 31, 2013 and 2012, respectively. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs. See the tables below for the classification of Transition Funding's assets and liabilities on the balance sheets.

Ohio Phase-in-Recovery Funding was formed for the sole purpose of issuing and servicing securitization bonds related to phase-in recovery property. Management has concluded that OPCo is the primary beneficiary of Ohio Phase-in-Recovery Funding because OPCo has the power to direct the most significant activities of the VIE and OPCo's equity interest could potentially be significant. Therefore, OPCo is required to consolidate Ohio Phase-in-Recovery Funding. The securitized bonds totaled $267 million as of December 31, 2013. Ohio Phase-in-Recovery Funding has securitized assets of $132 million as of December 31, 2013. The phase-in recovery property represents the right to impose and collect Ohio deferred distribution charges from customers receiving electric transmission and distribution service from OPCo under a recovery mechanism approved by the PUCO. In August 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to OPCo or any other AEP entity. OPCo acts as the servicer for Ohio Phase-in-Recovery Funding's securitized assets and remits all related amounts collected from customers to Ohio Phase-in-Recovery Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Ohio Phase-in-Recovery Funding's assets and liabilities on the balance sheet.

Appalachian Consumer Rate Relief Funding was formed for the sole purpose of issuing and servicing securitization bonds related to APCo's under-recovered ENEC deferral balance. Management has concluded that APCo is the primary beneficiary of Appalachian Consumer Rate Relief Funding because APCo has the power to direct the most significant activities of the VIE and APCo's equity interest could potentially be significant. Therefore, APCo is required to consolidate Appalachian Consumer Rate Relief Funding. The securitized bonds totaled $380 million as of December 31, 2013. Appalachian Consumer Rate Relief Funding has securitized assets of $369 million as of December 31, 2013. The phase-in recovery property represents the right to impose and collect West Virginia deferred generation charges from customers receiving electric transmission, distribution and generation service from APCo under a recovery mechanism approved by the WVPSC. In November 2013, securitization bonds were issued. The securitization bonds are payable only from and secured by the securitized assets. The bondholders have no recourse to APCo or any other AEP entity. APCo acts as the servicer for Appalachian Consumer Rate Relief Funding's securitized assets and remits all related amounts collected from customers to Appalachian Consumer Rate Relief Funding for interest and principal payments on the securitization bonds and related costs. See the table below for the classification of Appalachian Consumer Rate Relief Funding's assets and liabilities on the balance sheet.

The securitized bonds of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in current and long-term debt on the balance sheets. The securitized assets of Transition Funding, Ohio Phase-in-Recovery Funding and Appalachian Consumer Rate Relief Funding are included in securitized assets on the balance sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate EIS. Our insurance premium expense to the protected cell for the years ended December 31, 2013, 2012 and 2011 were $31 million, $32 million and $48 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on the balance sheets. The amount reported as equity is the protected cell's policy holders' surplus.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2013
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	OPCo Ohio Phase-in-Recovery Funding	APCo Appalachian Consumer Rate Relief Funding	Protected Cell of EIS
ASSETS							
Current Assets	$ 67	$ 118	$ 935	$ 232	$ 23	$ 6	$ 143
Net Property, Plant and Equipment	157	157	-	-	-	-	-
Other Noncurrent Assets	51	60	1	1,918 (a)	252 (b)	378 (c)	3
Total Assets	$ 275	$ 335	$ 936	$ 2,150	$ 275	$ 384	$ 146
LIABILITIES AND EQUITY							
Current Liabilities	$ 33	$ 108	$ 827	$ 312	$ 37	$ 14	$ 39
Noncurrent Liabilities	242	227	1	1,820	237	368	66
Equity	-	-	108	18	1	2	41
Total Liabilities and Equity	$ 275	$ 335	$ 936	$ 2,150	$ 275	$ 384	$ 146

(a) Includes an intercompany item eliminated in consolidation of $82 million.
(b) Includes an intercompany item eliminated in consolidation of $116 million.
(c) Includes an intercompany item eliminated in consolidation of $4 million.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2012
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	AEP Credit	TCC Transition Funding	Protected Cell of EIS
ASSETS					
Current Assets	$ 57	$ 133	$ 843	$ 250	$ 130
Net Property, Plant and Equipment	170	176	-	-	-
Other Noncurrent Assets	55	92	1	2,167 (a)	4

Total Assets	$ 282	$ 401	$ 844	$ 2,417	$ 134
LIABILITIES AND EQUITY					
Current Liabilities	$ 32	$ 121	$ 800	$ 304	$ 43
Noncurrent Liabilities	250	280	1	2,095	66
Equity	-	-	43	18	25
Total Liabilities and Equity	$ 282	$ 401	$ 844	$ 2,417	$ 134

(a) Includes an intercompany item eliminated in consolidation of $89 million.

DHLC is a mining operator that sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and voting rights equally. Each entity guarantees 50% of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. SWEPCo's total billings from DHLC for the years ended December 31, 2013, 2012 and 2011 were $60 million, $77 million and $62 million, respectively. We are not required to consolidate DHLC as we are not the primary beneficiary, although we hold a significant variable interest in DHLC. Our equity investment in DHLC is included in Deferred Charges and Other Noncurrent Assets on the balance sheets.

Our investment in DHLC was:

	December 31, 2013		December 31, 2012	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from SWEPCo	$ 8	$ 8	$ 8	$ 8
Retained Earnings	1	1	1	1
SWEPCo's Guarantee of Debt	-	61	-	49
Total Investment in DHLC	$ 9	$ 70	$ 9	$ 58

We and FirstEnergy Corp. (FirstEnergy) have a joint venture in Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct, through its operating companies, a high-voltage transmission line project in the PJM region. PATH consists of the "West Virginia Series (PATH-WV)," owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is 100% owned by a subsidiary of FirstEnergy. Provisions exist within the PATH-WV agreement that make it a VIE. The "Allegheny Series" is not considered a VIE. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheets. We and FirstEnergy share the returns and losses equally in PATH-WV. Our subsidiaries and FirstEnergy's subsidiaries provide services to the PATH companies through service agreements. The entities recover costs through regulated rates.

In August 2012, the PJM board cancelled the PATH Project, our transmission joint venture with FirstEnergy, and removed it from the 2012 Regional Transmission Expansion Plan. In September 2012, the PATH Project companies submitted an application to the FERC requesting authority to recover prudently-incurred costs associated with the PATH Project. In November 2012, the FERC issued an order accepting the PATH Project's abandonment cost recovery application, subject to settlement procedures and hearing. The settlement proceedings are ongoing.

Our investment in PATH-WV was:

	December 31, 2013		December 31, 2012	
	As Reported on the Balance Sheet	Maximum Exposure	As Reported on the Balance Sheet	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 19	$ 19	$ 19	$ 19
Retained Earnings	6	6	12	12
Total Investment in PATH-WV	$ 25	$ 25	$ 31	$ 31

As of December 31, 2013, our $25 million investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on the balance sheet. If we cannot ultimately recover our investment related to PATH-WV, it could reduce future net income and cash flows.

17. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following tables provide the annual property information:

2013	Regulated				Nonregulated		
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges
	(in millions)			(in years)	(in millions)		
Generation	$ 17,873	$ 7,168	1.7 - 3.7 %	31 - 132	$ 7,201	$ 2,969	2.6 - 3.3 %
Transmission	10,854	2,805	1.1 - 2.7 %	25 - 87	39	16	2.5 %
Distribution	16,377	3,988	2.3 - 3.8 %	11 - 75	-	-	NA
CWIP	2,326	(121)	NM	NM	145	1	NM
Other	4,116	1,931	2.0 - 7.9 %	5 - 75	1,354	531	NM
Total	$ 51,546	$ 15,771			$ 8,739	$ 3,517	

2012	Regulated				Nonregulated		
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges
	(in millions)			(in years)	(in millions)		
Generation	$ 16,973	$ 6,962	1.7 - 3.8 %	31 - 132	$ 9,306	$ 3,526	2.6 - 3.3 %
Transmission	9,846	2,720	1.2 - 2.8 %	25 - 87	-	-	NA
Distribution	15,565	3,837	2.4 - 3.9 %	11 - 75	-	-	NA
CWIP	1,600	(27)	NM	NM	219	1	NM
Other	2,644	1,238	1.8 - 9.6 %	5 - 75	1,301	434	NM
Total	$ 46,628	$ 14,730			$ 10,826	$ 3,961	

2011	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges
		(in years)		(in years)

Generation	1.6 - 3.8 %	9 - 132	2.6 - 3.5 %	20 - 66
Transmission	1.3 - 2.7 %	25 - 87	NA	NA
Distribution	2.4 - 4.0 %	11 - 75	NA	NA
CWIP	NM	NM	NM	NM
Other	1.7 - 9.3 %	5 - 55	NM	NM

NA Not applicable.
NM Not meaningful.

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

For regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2013 and 2012 aggregate carrying amounts of ARO:

	Carrying Amount of ARO (in millions)
ARO as of December 31, 2011 (a)	$ 1,474
Accretion Expense	85
Liabilities Incurred	17
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	144
ARO as of December 31, 2012	1,696
Accretion Expense	103
Liabilities Incurred	4
Liabilities Settled	(22)
Revisions in Cash Flow Estimates	54
ARO as of December 31, 2013	$ 1,835

(a) A current portion of ARO, totaling $2 million, is included in Other Current Liabilities on our 2011 balance sheet.

As of December 31, 2013 and 2012, our ARO liability included $1.2 billion and $1.2 billion, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2013 and 2012, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.6 billion and $1.4 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on the balance sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2013	2012	2011
		(in millions)	
Allowance for Equity Funds Used During Construction	$ 73	$ 93	$ 98
Allowance for Borrowed Funds Used During Construction	40	69	63

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included on the statements of income and the investments and accumulated depreciation are reflected on the balance sheets under Property, Plant and Equipment as follows:

			Company's Share as of December 31, 2013		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station, Unit 6 (a)	Coal	12.5 %	$ -	$ -	$ -
Conesville Generating Station, Unit 4 (b)	Coal	43.5 %	335	2	55
J.M. Stuart Generating Station (c)	Coal	26.0 %	544	11	190
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	809	2	399
Dolet Hills Generating Station, Unit 1 (d)	Lignite	40.2 %	262	47	198
Flint Creek Generating Station, Unit 1 (e)	Coal	50.0 %	123	54	66
Pirkey Generating Station, Unit 1 (e)	Lignite	85.9 %	519	29	376
Oklaunion Generating Station, Unit 1 (f)	Coal	70.3 %	404	7	223
Turk Generating Plant (e)	Coal	73.33 %	1,638	13	35
Transmission	NA	(g)	78	-	50
Total			$ 4,712	$ 165	$ 1,592

			Company's Share as of December 31, 2012		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station, Unit 6 (a)	Coal	12.5 %	$ -	$ -	$ -
Conesville Generating Station, Unit 4 (b)	Coal	43.5 %	310	26	59
J.M. Stuart Generating Station (c)	Coal	26.0 %	542	11	181
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	807	2	387
Dolet Hills Generating Station, Unit 1 (d)	Lignite	40.2 %	263	8	195
Flint Creek Generating Station, Unit 1 (e)	Coal	50.0 %	121	14	64
Pirkey Generating Station, Unit 1 (e)	Lignite	85.9 %	514	16	371
Oklaunion Generating Station, Unit 1 (f)	Coal	70.3 %	403	4	216
Turk Generating Plant (e)	Coal	73.33 %	1,613	(3)	-
Transmission	NA	(g)	69	4	50
Total			$ 4,642	$ 82	$ 1,523

(a) Operated by Duke Energy Corporation, a nonaffiliated company. AEP's portion of Beckjord Plant, Unit 6 was impaired in the fourth quarter of 2012. See "Impairments" section of Note 7.
(b) Operated by AGR.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.

(d) Operated by CLECO, a nonaffiliated company.
(e) Operated by SWEPCo.
(f) Operated by PSO and also jointly-owned (54.7%) by TNC.
(g) Varying percentages of ownership.
NANot applicable.

18. SUSTAINABLE COST REDUCTIONS

In April 2012, we initiated a process to identify strategic repositioning opportunities and efficiencies that will result in sustainable cost savings. We selected a consulting firm to facilitate an organizational and process evaluation and a second firm to evaluate our current employee benefit programs. The process resulted in involuntary severances and was 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.

We recorded a charge of $47 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the year ended December 31, 2013 is described in the following table:

	Sustainable Cost Reduction Activity (in millions)
Balance as of December 31, 2012	$ 25
Incurred	16
Settled	(31)
Adjustments	(9)
Balance as of December 31, 2013	$ 1

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the statements of income. Of the current period expense, approximately 43% was within the Generation & Marketing segment, 36% was within the Transmission and Distribution Utilities segment and 18% was within the Vertically Integrated Utilities segment. Of the total cumulative expense, approximately 51% was within the Vertically Integrated Utilities segment, 27% was within the Transmission and Distribution Utilities segment and 19% was within the Generation & Marketing segment. The remaining liability is included in Other Current Liabilities on the balance sheets. We do not expect additional costs to be incurred related to this initiative.

19. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our results of operations for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2013 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in millions - except per share amounts)			
Total Revenues	$ 3,826	$ 3,582	$ 4,176	$ 3,773
Operating Income	755	547 (a)	875 (c)	678 (d) (e)
Net Income	364	339 (a) (b)	434 (c)	347 (d) (e)
Amounts Attributable to AEP Common Shareholders:				
Net Income	363	338 (a) (b)	433 (c)	346 (d) (e)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.75	0.69	0.89	0.71
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (f)	0.75	0.69	0.89	0.71

	2012 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in millions - except per share amounts)			
Total Revenues	$ 3,625	$ 3,551	$ 4,156	$ 3,613
Operating Income	754	741	912	249 (g) (h)
Net Income	390	363	488	21 (g) (h)
Amounts Attributable to AEP Common Shareholders:				
Net Income	389	362	487	21 (g) (h)
Basic Earnings per Share Attributable to AEP				

Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05
Diluted Earnings per Share Attributable to AEP				
Common Shareholders:				
Earnings per Share (f)	0.80	0.75	1.00	0.05

(a) Includes an impairment for Muskingum River Plant, Unit 5 (see Note 7).
(b) Includes U.K. Windfall Tax benefit (see Note 12).
(c) Includes regulatory disallowances for the Turk Plant (see Note 4) and for Big Sandy Plant, Unit 2 (see Note 7).
(d) Includes a regulatory disallowance for Amos Plant, Unit 3 (see Note 7).
(e) Includes the reversal of regulatory disallowance for the Turk Plant (see Note 4).
(f) Quarterly Earnings per Share amounts are intended to be stand-alone calculations and are not always additive to full-year amount due to rounding.
(g) Includes impairments for certain Ohio generation plants (see Note 7).
(h) See Note 18 for discussion of cost reduction programs in 2012.

20. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2013 and 2012 by operating segment are as follows:

	Vertically Integrated Utilities	AEP River Operations	Generation and Marketing	AEP Consolidated
		(in millions)		
Balance as of December 31, 2011	$ 37	$ 39	$ -	$ 76
Acquired Goodwill	-	-	15	15
Impairment Losses	-	-	-	-
Balance as of December 31, 2012	37	39	15	91
Impairment Losses	-	-	-	-
Balance as of December 31, 2013	$ 37	$ 39	$ 15	$ 91

In the fourth quarters of 2013 and 2012, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

During 2012, the increase in goodwill of $15 million was due to the acquisition of BlueStar.

Other Intangible Assets

Acquired intangible assets subject to amortization were $10 million as of December 31, 2013, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on the balance sheets. During 2012, as a result of the acquisition of BlueStar, we acquired intangible assets associated with sales contracts and customer accounts of $58 million. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,			
		2013		2012	
	Amortization Life	Gross Carrying Amount	Accumulated Amortization	Gross Carrying Amount	Accumulated Amortization
	(in years)		(in millions)		
Acquired Customer Contracts	5	$ 58	$ 48	$ 58	$ 34

Amortization of intangible assets was $14 million, $34 million and $1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Our estimated total amortization is $6 million, $3 million and $1 million for 2014, 2015 and 2016, respectively.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page – Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings – Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders – (Stock held in a bank or brokerage account) – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/buyandmanagestock.

Financial Community Inquiries – Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; or Julie Sherwood, 614-716-2663, jasherwood@AEP.com. Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders – As of February 24, 2014, there were approximately 77,500 registered shareholders and approximately 446,000 shareholders holding stock in street name through a bank or broker. There were 487,820,462 shares outstanding as of February 24, 2014.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2013. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	Office
Nicholas K. Akins	53	Chairman of the Board, President and Chief Executive Officer
Lisa M. Barton	48	Executive Vice President – Transmission
David M. Feinberg	44	Executive Vice President, General Counsel and Secretary
Lana L. Hillebrand	53	Senior Vice President and Chief Administrative Officer
Mark C. McCullough	54	Executive Vice President – Generation
Robert P. Powers	59	Executive Vice President and Chief Operating Officer
Brian X. Tierney	46	Executive Vice President and Chief Financial Officer
Dennis E. Welch	62	Executive Vice President and Chief External Officer

Filing Requirement
807 KAR 5:001 Section 16 (4)(r)

Filing Requirement:

The monthly managerial reports providing financial results of operations for the twelve months in the test period;

Response:

Please see the Company's monthly financial reports for the months of October 2013 through September 2014 attached.

AEP AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

November 25, 2013

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed October 2013 Financial Report pages for Kentucky Power Company consisting of the following:

Page Nos.	Description
1-11	Income Statement
1-3	Details of Operating Revenues
4-9	Operating Expenses – Functional Expenses
10-11	Detail Statement of Taxes
12	Balance Sheet – Assets & Other Debits
13-14	Balance Sheet – Liabilities & Other Credits
13-14	Deferred Credits
15	Statement of Retained Earnings
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Bradley M. Funk

Bradley M. Funk
Manager –Regulated Accounting

BMF

Enclosure
Cc: Lila Munsey (w/pages)

Kentucky Power Corp Consol
Comparative Income Statement

11/08/2013 18:31

Oct 2013 — Layout: GLA8094V
09B V2099-01-01 — Account: GL_ACCT_SEC — Business Unit: GL_PRPT_CONS

Account		Description	Current Month Oct 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Oct 2013
		REVENUES				
4400001		Residential Sales-W/Space Htg	6,034,717	19,224,321	60,918,068	100,508,044
4400002		Residential Sales-W/O Space Ht	3,326,383	10,964,174	38,973,536	46,963,107
4400005		Residential Fuel Rev	3,904,329	12,901,716	54,050,877	66,054,953
	A	**Revenue - Residential Sales**	**13,265,429**	**43,090,211**	**173,942,500**	**213,526,105**
4420001		Commercial Sales	5,686,039	16,272,370	54,112,393	64,380,626
4420006		Sales to Pub Auth - Schools	1,080,773	3,099,332	9,822,581	11,759,342
4420007		Sales to Pub Auth - Ex Schools	1,065,032	3,043,946	10,171,838	12,095,374
4420013		Commercial Fuel Rev	3,323,084	9,646,077	32,988,006	38,848,742
	A	**Revenue - Commercial Sales**	**11,154,927**	**32,061,725**	**107,094,818**	**127,084,084**
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	4,699,960	13,509,137	46,043,493	52,492,853
4420004		Ind Sales-NonAffil(Incl Mines)	2,324,554	6,413,547	23,701,112	28,854,712
4420016		Industrial Fuel Rev	6,794,545	19,971,433	69,814,388	84,328,716
	A	**Revenue - Industrial Sales - NonAffiliated**	**13,819,059**	**39,894,117**	**139,568,992**	**165,676,281**
		Revenue - Industrial Sales	**13,819,059**	**39,894,117**	**139,558,992**	**165,676,281**
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	103,793	312,242	1,054,572	1,252,921
4440002		Public St & Hwy Light Fuel Rev	28,705	74,283	243,009	303,676
	A	**Revenue - Other Retail Sales**	**132,497**	**386,525**	**1,297,581**	**1,556,597**
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**38,371,913**	**115,432,579**	**421,893,891**	**507,843,068**
	B					
4561033		PJM NITS Revenue - Affiliated	3,245,409	9,652,050	30,182,527	36,421,574
4561034		PJM TO Adm. Serv Rev - Aff	-	89,675	330,436	372,450
4561035		PJM Affiliated Trans NITS Cost	(3,191,692)	(9,471,931)	(29,565,163)	(35,573,036)
4561036		PJM Affiliated Trans TO Cost	46	(88,982)	(321,785)	(363,082)
4561059		Affil PJM Trans Enhancmnt Rev	27,851	83,730	230,186	270,592
4561060		Affil PJM Trans Enhancmnt Cost	(27,390)	(82,168)	(225,488)	(264,393)
4561062		PROVISION PJM NITS Affil- Cost	(63,501)	(190,631)	538,442	553,106
4561063		PROVISION PJM NITS Affiliated	(18,675)	(56,491)	(241,607)	(385,553)
	B	**Revenue - Transmission-Affiliated**	**(27,952)**	**(64,747)**	**927,548**	**1,031,656**
4470004		Sales for Resale-Nonaff-Ancill	-	-	-	-
4470005		Sales for Resale-Nonaff-Transm	-	-	-	-
4470150		Transm. Rev -Dedic. Whlsl/Muni	1,892	13,754	40,542	54,013
4470206		PJM Trans loss credits-OSS	27,944	431,348	830,931	935,068
4470207		PJM transm loss charges - LSE	(568,022)	(800,407)	(6,543,943)	(8,291,892)
4470208		PJM Transm loss credits-LSE	119,669	118,424	1,411,396	1,708,507
4470209		PJM transm loss charges-OSS	(216,185)	(2,038,477)	(3,859,356)	(4,452,227)
4561002		RTO Formation Cost Recovery	130	1,484	3,754	7,393
4561003		PJM Expansion Cost Recov	6,772	21,042	69,426	84,752
4561004		SECA Transmission Rev	-	-	-	227,184
4561005		PJM Point to Point Trans Svc	57,897	159,161	511,026	634,515
4561006		PJM Trans Owner Admin Rev	20,069	62,383	181,405	210,052
4561007		PJM Network Integ Trans Svc	1,209,033	3,567,585	10,710,877	12,657,603
4561019		Oth Elec Rev Trans Non Affil	4,028	11,642	45,953	56,549
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	810	1,700	6,600	8,333
4561029		PJM NITS Revenue Whsl Cus-NAff	211,131	626,581	1,938,254	2,355,272
4561030		PJM TO Serv Rev Whls Cus-NAff	3,260	10,092	29,943	35,213
4561058		NonAffil PJM Trans Enhncmt Rev	27,417	82,073	198,445	227,043
4561061		NAff PJM RTEP Rev for Whsl-FR	1,812	5,435	14,796	17,497
4561064		PROVISION PJM NITS WhslCus-NA/	(1,187)	(3,562)	(16,344)	(24,959)
4561065		PROVISION PJM NITS	(6,378)	(18,669)	(64,994)	(90,056)
	A	**Revenue - Transmission-NonAffiliated**	**900,091**	**2,251,588**	**5,508,712**	**6,359,860**
		Revenue - Transmission	**872,139**	**2,186,841**	**6,436,260**	**7,391,516**
4210026		B/L Affl MTM Assign	-	-	-	-
4210028		Realized Affil Financial Assgn	-	-	-	-
4210045		UnReal Aff Fin Assign SNWA	-	-	-	-
4210046		Real Aff Fin Assign SNWA	-	-	-	-
4470001		Sales for Resale - Assoc Cos	1,693	4,216	7,483	6,960
4470035		Sls for Rsl - Fuel Rev - Assoc	11,086	19,877	80,909	85,534
4470128		Sales for Res-Aff. Pool Energy	1,141,973	9,229,280	35,662,008	38,626,667
4560111		MTM Aff GL Coal Trading	-	-	-	-
4560112		Realized GL Coal Trading-Affil	-	-	-	-
	B	**Revenue - Resale-Affiliated**	**1,154,753**	**9,253,373**	**35,750,400**	**38,719,162**

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Oct 2013 / 09B V2099-01-01	Layout: GLA6094V / Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS		Current Month Oct 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Oct 2013
4210025		B/L MTM Assignments	-	-	-	-
4210027		Realized Financial Assignments	-	-	-	-
4210035		Gn/Ls MTM Emissions - Forwards	-	-	-	-
4210043		Realiz Sharing West Coast Pwr	-	-	15	15
4470002		Sales for Resale - NonAssoc	181,027	1,032,977	3,424,137	4,605,885
4470006		Sales for Resale-Bookout Sales	1,064,503	3,513,228	12,691,139	15,356,264
4470007		Sales for Resale-Option Sales	-	-	-	-
4470010		Sales for Resale-Bookout Purch	(707,054)	(2,386,295)	(8,937,272)	(10,861,582)
4470011		Sales for Resale-Option Purch	-	-	-	-
4470027		Whsal/Muni/Pb Ath Fuel Rev	201,484	734,252	2,304,376	2,832,054
4470028		Sale/Resale - NA - Fuel Rev	308,872	832,405	3,149,260	5,440,597
4470033		Whsal/Muni/Pub Auth Base Rev	155,790	542,469	1,426,838	1,936,334
4470066		PWR Trding Trans Exp-NonAssoc	370	(148)	(2,091)	(3,593)
4470081		Financial Spark Gas - Realized	38,672	118,157	386,361	425,824
4470082		Financial Electric Realized	(386,858)	(1,095,896)	(2,832,903)	(3,764,801)
4470089		PJM Energy Sales Margin	234,708	2,395,222	7,588,157	8,219,270
4470093		PJM Implicit Congestion-LSE	(154,606)	313,135	(3,325,416)	(3,889,805)
4470098		PJM Oper Reserve Rev-OSS	131,052	603,508	1,433,335	1,650,527
4470099		Capacity Cr. Net Sales	38,235	116,425	376,977	452,334
4470100		PJM FTR Revenue-OSS	5,128	224,419	344,301	372,627
4470101		PJM FTR Revenue-LSE	111,491	216,409	2,427,893	2,912,879
4470103		PJM Energy Sales Cost	4,600,510	17,039,979	49,172,175	57,413,052
4470106		PJM Pt2Pt Trans Purch-NonAff	(30)	(53)	(1,311)	(1,801)
4470107		PJM NITS Purch-NonAff	(1,837)	(6,832)	(16,711)	(19,978)
4470109		PJM FTR Revenue-Spec	9,105	53,708	726	(24,197)
4470110		PJM TO Admin. Exp.-NonAff	(443)	(700)	(905)	(957)
4470112		Non-Trading Bookout Sales-OSS	-	-	(2,027)	72,867
4470115		PJM Meter Corrections-OSS	(13,826)	(16,641)	(12,428)	(50,096)
4470116		PJM Meter Corrections-LSE	(30,896)	(29,323)	25,066	27,461
4470124		PJM Incremental Spot-OSS	(0)	(0)	(0)	(0)
4470126		PJM Incremental Imp Cong-OSS	(105,253)	(1,603,809)	(2,900,894)	(3,070,274)
4470131		Non-Trading Bookout Purch-OSS	-	-	180	16
4470141		PJM Contract Net Charge Credit	119	481	-	(0)
4470143		Financial Hedge Realized	13,764	150,401	116,903	133,786
4470144		Realiz.Sharing - 06 SIA	61	819	1,404	276
4470155		OSS Physical Margin Reclass	(102,991)	(381,006)	(1,068,387)	(1,597,766)
4470156		OSS Optim. Margin Reclass	102,991	381,006	1,068,387	1,597,766
4470167		MISO FTR Revenues OSS	-	-	-	-
4470168		Interest Rate Swaps-Power	-	(9,105)	(27,370)	(36,308)
4470169		Capacity Sales Trading	-	-	-	-
4470170		Non-ECR Auction Sales-OSS	268,846	870,393	4,461,843	5,583,979
4470174		PJM Whlse FTR Rev - OSS	3,512	9,702	101,844	148,382
4470175		OSS Sharing Reclass - Retail	(764,776)	(1,901,906)	(777,535)	(1,703,959)
4470176		OSS Sharing Reclass-Reduction	764,776	1,901,906	777,535	1,703,959
4470180		Trading intra-book Reclass	2,263	17,333	(873)	(24,159)
4470181		Auction intra-book Reclass	(2,263)	(17,333)	873	24,159
4470202		PJM OpRes-LSE-Credit	350,316	993,440	3,402,751	3,984,731
4470203		PJM OpRes-LSE-Charge	(169,124)	(448,978)	(1,533,830)	(1,977,675)
4470214		PJM 30m Suppl Reserve CR OSS	30	26,415	247,631	248,540
4470215		PJM 30m Suppl Reserve CH OSS	-	-	-	-
4470220		PJM Regulation - OSS	146	(547)	10,110	10,110
4470221		PJM Spinning Reserve - OSS	6,237	12,495	33,018	33,018
4470222		PJM Reasctive - OSS	35,613	102,648	344,537	344,537
4560016		Financial Trading Rev-Unreal	-	-	-	-
4560049		Merch Generation Finan -Realzd	-	-	(2)	(2)
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	1,794	(34)	30,284	(18,069)
5550080		PJM Hourly Net Purch.-FERC	(780,678)	(2,326,821)	(7,875,535)	(9,379,601)
5550094		Purchased Power - Fuel	(69,440)	(177,984)	(460,374)	(678,366)
	A	**Revenue - Resale-NonAffiliated**	**5,341,339**	**21,799,920**	**65,672,211**	**78,428,258**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**6,496,092**	**31,053,293**	**101,322,611**	**117,147,420**
4540001		Rent From Elect Property - Af	21,851	65,553	218,510	263,517
	B	**Revenue - Other Ele-Affiliated**	**21,851**	**65,553**	**218,510**	**263,517**
4210049		Interest Rate Swaps-BTL Power	-	-	-	-
4210053		Specul. Allow. Gains-SO2	-	-	-	-
4210054		Specul. Allow. Gains-Seas NOx	-	-	-	-
4265053		Specul. Allow Loss-SO2	-	-	-	-

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Account		Description	Current Month Oct 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Oct 2013
4265054		Specul Allow Loss-Seas NOx	-	-	-	-
4265056		Specul Allow Loss-CO2	-	-	-	-
4500000		Forfeited Discounts	276,231	817,666	2,854,524	3,339,095
4510001		Misc Service Rev - Nonaffil	44,986	100,534	336,275	374,867
4540002		Rent From Elect Property-NAC	17,150	17,450	70,903	111,792
4540005		Rent from Elec Prop-Pole Attch	434,857	1,316,405	5,051,682	5,911,508
4560007		Oth Elect Rev - DSM Program	355,551	482,841	2,418,819	2,931,610
4560012		Oth Elect Rev - Nonaffiliated	-	-	-	-
4560041		Miscellaneous Revenue-NonAffil	-	-	-	-
4560109		Interest Rate Swaps-Coal	-	-	-	-
		Revenue - Other Ele-NonAffiliated	**1,128,774**	**2,734,896**	**10,732,203**	**12,668,872**
		Revenue - Gas	-	-	-	-
4118002		Comp Allow Gains Title IV SO2	-	-	164	164
4118003		Comp Allow Gains-Seas NOx	7,766	17,766	17,766	32,724
4118004		Comp Allow Gains-Ann NOx	-	36,783	92,184	92,184
		Gain/(Loss) on Allowances	**7,766**	**54,549**	**110,114**	**125,072**
	A	**Revenue - Other Ele-NonAffiliated**	**1,136,540**	**2,789,446**	**10,842,317**	**12,793,944**
		Revenue - Other Opr Electric	**1,168,391**	**2,854,999**	**11,060,627**	**13,057,461**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	2,600	7,800	30,400	39,600
4180002		Non-Opratng Rntal Inc-Oper	-	-	-	(330)
4180003		Non-Opratng Rntal Inc-Maint	-	(23)	(772)	(772)
4180005		Non-Opratng Rntal Inc-Depr	(556)	(1,667)	(5,558)	(6,670)
	D	**Non-Operating Rental Income - NonAffiliated**	**2,044**	**6,110**	**24,070**	**31,828**
		Non-Operating Rental Income	**2,044**	**6,110**	**24,070**	**31,828**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210000		Misc Non-Operating Income	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	145	440	20,015	48,353
4210003		Misc Non-Op Inc-NonAscRoylty	-	-	-	-
4210005		Misc Non-Op Inc-NonAsc-Timber	1,629	36,508	36,616	53,321
4210007		Misc Non-Op Inc - NonAsc - Oth	63	192	10,800	13,844
	D	**Non-Operating Misc Income - NonAffiliated**	**1,837**	**37,139**	**67,430**	**115,518**
		Non-Operating Misc Income	**1,837**	**37,139**	**67,430**	**115,518**
4540004		Rent From Elect Prop-ABD-Nonaf	2,645	33,297	84,466	101,742
4560015		Other Electric Revenues - ABD	46,909	108,974	330,690	327,269
	D	**Associated Business Development Income**	**49,554**	**142,271**	**415,156**	**429,011**
		Revenue - Other Opr - Other	**53,435**	**185,520**	**506,655**	**576,357**
	=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
	=(D)	*Memo: Revenue-Oth Opr-Oth Non*	*53,435*	*185,520*	*506,655*	*576,357*
		Revenue - Other Operating	**1,211,827**	**3,040,519**	**11,567,482**	**13,633,818**
4491003		Prov Rate Refund - Retail	-	(71,158)	407,169	407,169
	A	**Provision for Rate Refund - NonAffiliated**	-	**(71,158)**	**407,169**	**407,169**
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	-	**(71,158)**	**407,169**	**407,169**
4210031		Pwr Sales Outside Svc Territry	-	(4)	1,267	1,267
4210032		Pwr Purch Outside Svc Territry	-	-	(539)	(539)
4210033		Mark to Mkt Out Svc Territory	-	-	-	-
	A	**Revenue - Power Sales**	-	**(4)**	**728**	**728**
		TOTAL OPERATING REVENUES	**46,951,970**	**151,642,069**	**541,628,142**	**646,423,719**
	=(A)	*Memo: G/T/D Revenue*	*45,749,883*	*142,202,370*	*504,225,028*	*605,833,027*
	=(B)	*Memo: Other Affiliated Revenue*	*1,148,652*	*9,254,179*	*36,896,459*	*40,014,335*
	=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
	=(D)	*Memo: Revenue-Oth Opr-Oth Non*	*53,435*	*185,520*	*506,655*	*576,357*
		Memo: Total Operating Revenues	*46,951,970*	*151,642,069*	*541,628,142*	*646,423,719*
	=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***1,148,652***	*9,254,179*	*36,896,459*	*40,014,335*
	=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***45,803,318***	*142,387,890*	*504,731,684*	*606,409,384*
		Memo: Total Operating Revenues	*46,951,970*	*151,642,069*	*541,628,142*	*646,423,719*

FUEL EXPENSES

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5010000	Fuel	34,904	195,606	248,363	313,665
5010001	Fuel Consumed	312,525	7,723,078	78,480,891	83,323,161
5010003	Fuel - Procure Unload & Handle	12,168	266,877	2,449,696	2,655,724
5010012	Ash Sales Proceeds	-	(9,325)	(9,325)	(9,325)
5010013	Fuel Survey Activity	-	-	-	1
5010019	Fuel Oil Consumed	12,116	44,425	1,637,928	2,633,942
	Fuel Expense Total	**371,712**	**8,220,661**	**82,807,553**	**88,917,168**
5010005	Fuel - Deferred	(683,118)	(1,110,723)	(3,029,401)	(1,623,730)
	Deferred Fuel Expense	**(683,118)**	**(1,110,723)**	**(3,029,401)**	**(1,623,730)**
	Over Under Fuel Expense	-	-	-	-
	Fuel for Electric Generation	**(311,406)**	**7,109,938**	**79,778,153**	**87,293,458**
	Fuel from Affiliates for Electric Generation	-	-	-	-
5090000	Allow Consum Title IV SO2	149,044	727,442	4,679,393	5,239,916
5090002	Allowance Expenses	-	-	1	1
5090005	An. NOx Cons. Exp	971	4,480	10,904	21,297
	Allowances - Consumption	**150,015**	**731,922**	**4,690,298**	**5,261,214**
5020002	Urea Expense	131	684	1,748,234	1,850,307
5020003	Trona Expense	-	-	-	12
5020008	Activated Carbon	-	-	-	(72)
	Emissions Control - Chemicals	**131**	**684**	**1,748,234**	**1,850,247**
	Total Fuel for Electric Generation	**(161,260)**	**7,842,544**	**86,216,686**	**94,404,919**
	Memo: NonAff Fuel/Allow/Emissions	**(161,260)**	**7,842,544**	**86,216,686**	**94,404,919**
5550004	Purchased Power-Pool Capacity	2,537,270	7,790,275	22,761,927	26,640,986
5550005	Purchased Power - Pool Energy	8,310,045	25,017,600	63,085,191	78,180,346
5550027	Purch Pwr-Non-Fuel Portion-Aff	3,762,803	11,070,634	38,222,608	44,250,278
5550046	Purch Power-Fuel Portion-Affil	5,843,445	16,645,772	47,601,861	58,744,426
5550101	Purch Power-Pool Non-Fuel -Aff	1,046,467	3,053,589	8,461,192	10,543,791
5550102	Pur Power-Pool NonFuel-OSS-Aff	4,059,250	15,299,487	43,382,476	52,110,620
	Purchased Electricity from AEP - Affiliates	**25,559,280**	**78,877,357**	**223,515,255**	**270,470,447**
5550001	Purch Pwr-NonTrading-Nonassoc	111,921	190,786	828,817	871,609
5550023	Purch Power Capacity -NA	-	-	-	-
5550032	Gas-Conversion-Mone Plant	31,799	125,577	361,710	397,739
5550036	PJM Emer Energy Purch	-	-	-	-
5550039	PJM Inadvertent Mtr Res-OSS	(1,851)	(6,396)	(12,239)	(11,974)
5550040	PJM Inadvertent Mtr Res-LSE	(4,147)	(10,984)	(25,190)	(19,498)
5550041	PJM Ancillary Serv -Sync	(51)	(132)	2,494	4,310
5550074	PJM Reactive-Charge	566	1,713	5,584	6,874
5550075	PJM Reactive-Credit	9,475	28,461	93,225	111,350
5550076	PJM Black Start-Charge	315,227	918,823	3,522,216	3,529,816
5550077	PJM Black Start-Credit	(1,044)	(3,131)	(9,722)	(15,815)
5550078	PJM Regulation-Charge	72,543	265,169	1,156,505	1,482,097
5550079	PJM Regulation-Credit	(14,613)	(69,279)	(337,247)	(501,740)
5550083	PJM Spinning Reserve-Charge	2,266	20,731	44,843	42,300
5550084	PJM Spinning Reserve-Credit	(1,113)	(11,310)	(14,213)	(15,486)
5550090	PJM 30m Suppl Rserv Charge LSE	(4,108)	32,276	275,861	276,269
5550099	PJM Purchases-non-ECR-Auction	168,185	593,809	3,406,636	4,324,253
5550100	Capacity Purchases-Auction	7,228	21,705	69,343	74,183
5550107	Capacity purchases - Trading	9,626	28,603	164,122	217,784
	Purchased Electricity for Resale - NonAffiliated	**701,907**	**2,126,440**	**9,534,746**	**10,774,070**
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	**26,261,187**	**81,003,797**	**233,050,001**	**281,244,517**
	GROSS MARGIN	**20,862,043**	**62,795,728**	**222,381,455**	**270,774,283**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	148,265	447,809	1,438,576	1,887,746
5000001	Oper Super & Eng-RATA-Affil	-	-	28,000	28,000
5020000	Steam Expenses	92,035	199,226	681,940	852,880
5020025	Steam Exp Environmental	-	(13)	(7)	(63)
5050000	Electric Expenses	25,848	71,313	365,721	418,806
5060000	Misc Steam Power Expenses	297,024	778,553	3,157,175	4,504,542
5060001	Dresden Misc Steam Pwer Exp	4	4	4	4
5060002	Misc Steam Power Exp-Assoc	1,589	5,599	17,920	23,445
5060004	NSR Settlement Expense	-	-	(5,898)	(7,837)
5060006	Voluntary CO2 Compliance Exp	-	-	-	-
5060025	Misc Stm Pwr Exp Environmental	(2)	(18)	12	12
5070000	Rents	-	-	900	900

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	Steam Generation Op Exp	**564,764**	**1,502,473**	**5,684,342**	**7,708,435**
5170000	Oper Supervision & Engineering	-	-	1,074	1,074
	Nuclear Generation Op Exp	-	-	**1,074**	**1,074**
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	17,419	44,253	102,726	123,512
5570000	Other Expenses	108,526	418,660	1,083,176	1,356,700
5570007	Other Pwr Exp - Wholesale RECs	7,310	7,310	11,412	13,977
5570008	Other Pwr Exp - Voluntary RECs	-	-	-	-
5757000	PJM Admin-MAM&SC- OSS	24,757	102,257	278,691	292,693
5757001	PJM Admin-MAM&SC- Internal	48,625	141,290	561,924	723,004
	Other Generation Op Exp	**206,637**	**713,771**	**2,037,928**	**2,509,887**
5600000	Oper Supervision & Engineering	116,097	275,218	710,532	859,188
5610000	Load Dispatching	-	-	-	-
5611000	Load Dispatch - Reliability	715	3,770	7,591	9,144
5612000	Load Dispatch-Mntr&Op TransSys	79,029	235,993	663,768	809,618
5613000	Load Dispatch-Trans Srvc&Sched	-	-	-	-
5614000	PJM Admin-SSC&DS-OSS	24,220	97,904	271,673	283,680
5614001	PJM Admin-SSC&DS-Internal	46,251	135,737	561,537	714,242
5614007	RTO Admin Default LSE	-	-	(8,058)	(8,058)
5614008	PJM Admin Defaults OSS	-	-	-	-
5615000	Reliability,Plng&Stds Develop	13,438	60,672	127,297	154,054
5618000	PJM Admin-RP&SDS-OSS	5,174	20,165	57,978	60,827
5618001	PJM Admin-RP&SDS- Internal	10,417	28,349	134,031	167,211
5620001	Station Expenses - Nonassoc	6,515	70,551	190,857	219,433
5630000	Overhead Line Expenses	8,580	9,932	78,533	110,302
5640000	Underground Line Expenses	-	-	-	-
5650002	Transmssn Elec by Others-NAC	13,970	39,036	152,012	183,050
5650003	AEP Trans Equalization Agmt	-	-	-	-
5650012	PJM Trans Enhancement Charge	292,111	877,893	2,954,308	3,499,501
5650015	PJM TO Serv Exp - Aff	1,265	1,265	2,128	2,128
5650016	PJM NITS Expense - Affiliated	328,843	975,907	2,004,881	2,253,750
5650018	PJM Trans Enhancement Credits	-	-	-	-
5650019	Affil PJM Trans Enhncement Exp	16,221	48,662	97,589	108,588
5650020	PROVISION PJM NITS Affl Expens	(8,219)	(75,942)	295,776	308,109
5660000	Misc Transmission Expenses	143,216	302,347	851,136	1,262,511
5670001	Rents - Nonassociated	-	1,546	6,339	6,439
5670002	Rents - Associated	-	-	-	303
5757002	SPP Admin-MAM&SC	-	0	0	0
	Transmission Op Exp	**1,097,843**	**3,109,006**	**9,159,910**	**11,004,020**
5800000	Oper Supervision & Engineering	68,848	175,337	589,651	658,332
5810000	Load Dispatching	323	847	2,673	3,222
5820000	Station Expenses	8,804	27,880	122,339	154,034
5830000	Overhead Line Expenses	55,674	105,874	420,386	443,809
5840000	Underground Line Expenses	12,118	38,556	114,715	135,920
5850000	Street Lighting & Signal Sys E	7,323	46,107	102,308	115,630
5860000	Meter Expenses	107,147	248,887	501,667	505,710
5870000	Customer Installations Exp	16,390	45,983	140,404	163,266
5880000	Miscellaneous Distribution Exp	375,762	925,563	3,283,130	4,524,845
5890001	Rents - Nonassociated	129,936	351,431	1,294,906	1,617,758
5890002	Rents - Associated	5,469	16,407	54,688	63,895
	Distribution Op Exp	**787,794**	**1,982,870**	**6,626,867**	**8,386,421**
9010000	Supervision - Customer Accts	25,830	71,854	241,642	288,366
9020000	Meter Reading Expenses	180	711	2,403	4,777
9020001	Customer Card Reading	-	-	-	0
9020002	Meter Reading - Regular	37,381	97,650	330,333	393,062
9020003	Meter Reading - Large Power	1,782	7,350	31,393	39,202
9020004	Read-In & Read-Out Meters	5,882	15,725	37,959	43,703
9030000	Cust Records & Collection Exp	25,789	78,424	283,236	375,326
9030001	Customer Orders & Inquiries	181,154	510,161	1,675,905	2,161,964
9030002	Manual Billing	2,717	8,044	28,067	36,819
9030003	Postage - Customer Bills	72,499	234,458	720,232	864,411
9030004	Cashiering	8,870	33,506	104,397	126,849
9030005	Collection Agents Fees & Exp	4,552	20,663	27,726	42,885
9030006	Credit & Oth Collection Activi	69,064	196,768	633,036	778,171
9030007	Collectors	46,333	139,516	472,473	595,219
9030009	Data Processing	16,160	41,976	136,448	164,235
9040007	Uncoll Accts - Misc Receivable	16,348	66,156	(52,029)	62,501
9050000	Misc Customer Accounts Exp	1,782	4,637	16,863	19,160
9070000	Supervision - Customer Service	15,242	35,813	118,845	163,406
9070001	Supervision - DSM	(2)	-	(2)	(43)

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9080000	Customer Assistance Expenses	42,669	124,173	396,487	488,513
9080001	DSM-Customer Advisory Grp	14	150	609	647
9080004	Cust Assistnce Exp - DSM - Ind	-	-	(1)	(5)
9080009	Cust Assistance Expense - DSM	282,463	1,030,427	2,300,431	2,680,844
9090000	Information & Instruct Advrtis	8,217	73,527	80,394	149,650
9100000	Misc Cust Svc&Informational Ex	497	4,487	21,887	29,323
9100001	Misc Cust Svc & Info Exp - RCS	-	-	-	-
	Customer Service and Information Op Exp	**865,425**	**2,796,176**	**7,608,732**	**9,508,989**
9110001	Supervision - Residential	-	-	-	-
9110002	Supervision - Comm & Ind	-	-	-	-
9120000	Demonstrating & Selling Exp	1,590	5,905	17,859	17,859
9120001	Demo & Selling Exp - Res	-	-	2	4
9120003	Demo & Selling Exp - Area Dev	-	-	-	-
	Sales Expenses	**1,590**	**5,905**	**17,861**	**17,863**
	Memo: Insurance (9240 9250)	**49,706**	**308,936**	**2,084,799**	**2,305,297**
9200000	Administrative & Gen Salaries	730,146	1,845,752	7,645,926	9,447,714
9200003	Admin & Gen Salaries Trnsfr	-	-	-	-
9210001	Off Supl & Exp - Nonassociated	61,675	177,728	1,115,877	1,162,477
9210003	Office Supplies & Exp - Trnsf	1	1	57	57
9210004	Office Utilites	-	-	-	-
9210005	Cellular Phones and Pagers	-	-	-	-
9220000	Administrative Exp Trnsf - Cr	(34,371)	(109,578)	(479,339)	(629,718)
9220001	Admin Exp Trnsf to Cnstrction	(45,169)	(134,829)	(471,127)	(589,890)
9220004	Admin Exp Trnsf to ABD	(97)	(178)	(4,209)	(5,376)
9220125	SSA Expense Transfers BL	-	-	-	(106,948)
9230001	Outside Svcs Empl - Nonassoc	142,185	607,232	1,960,937	2,381,541
9230003	AEPSC Billed to Client Co	74,711	(121,322)	(657,921)	381,233
9240000	Property Insurance	39,316	118,096	471,221	576,188
9250000	Injuries and Damages	93,215	279,645	909,351	1,099,404
9250001	Safety Dinners and Awards	173	268	1,467	1,660
9250002	Emp Accdent Prvntion-Adm Exp	785	2,873	10,432	12,771
9250004	Injuries to Employees	-	-	10	337
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(58,435)	5,446	924,027	899,528
9250007	Prsnal Injries&Prop Dmage-Pub	16,686	73,596	80,392	81,633
9250010	Frg Ben Loading - Workers Comp	(42,033)	(170,987)	(312,100)	(366,224)
9260000	Employee Pensions & Benefits	373	(178)	4,117	4,838
9260001	Edit & Print Empl Pub-Salaries	843	2,400	8,455	15,327
9260002	Pension & Group Ins Admin	181	4,883	19,898	24,507
9260003	Pension Plan	338,160	1,014,479	3,381,598	3,922,421
9260004	Group Life Insurance Premiums	10,381	31,536	105,986	129,133
9260005	Group Medical Ins Premiums	262,993	819,548	3,126,356	3,685,493
9260006	Physical Examinations	-	11	28	28
9260007	Group L-T Disability Ins Prem	1,166	3,506	11,768	11,506
9260009	Group Dental Insurance Prem	18,796	58,459	197,866	233,808
9260010	Training Administration Exp	1,445	(3,308)	2,558	2,940
9260012	Employee Activities	2,545	2,810	4,834	5,709
9260014	Educational Assistance Pmts	-	-	4,761	5,466
9260021	Postretirement Benefits - OPEB	(125,025)	(375,074)	(1,250,245)	(1,009,828)
9260026	Savings Plan Administration	-	-	-	-
9260027	Savings Plan Contributions	113,762	333,090	1,109,370	1,450,940
9260036	Deferred Compensation	-	70,699	(1,406)	12,210
9260037	Supplemental Pension	325	974	3,246	3,366
9260050	Frg Ben Loading - Pension	(148,922)	(410,909)	(1,323,489)	(1,599,630)
9260051	Frg Ben Loading - Grp Ins	(155,781)	(445,744)	(1,582,447)	(1,977,096)
9260052	Frg Ben Loading - Savings	(51,727)	(137,548)	(450,693)	(609,848)
9260053	Frg Ben Loading - OPEB	29,008	94,217	29,058	(139,846)
9260055	IntercoFringeOffset- Don't Use	(79,854)	(233,105)	(744,224)	(989,606)
9260056	Fidelity Stock Option Admin	-	-	-	-
9260057	Postret Ben Medicare Subsidy	41,089	123,267	410,891	502,962
9260058	Frg Ben Loading - Accrual	(57,096)	(142,655)	(208,812)	57,751
9260060	Amort-Post Retirement Benefit	18,052	54,155	180,517	180,517
9270000	Franchise Requirements	11,629	35,532	119,090	143,449
9280000	Regulatory Commission Exp	292	165	1,358	1,346
9280001	Regulatory Commission Exp-Adm	-	(19)	(0)	(5)
9280002	Regulatory Commission Exp-Case	8,054	70,217	170,456	195,081
9301000	General Advertising Expenses	(88)	128	257	6,883
9301001	Newspaper Advertising Space	-	8,692	20,114	27,301
9301002	Radio Station Advertising Time	4	12	42	632
9301003	TV Station Advertising Time	-	-	-	-
9301006	Spec Corporate Comm Info Proj	-	-	-	-

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Oct 2013 09B V2009-01-01	Layout: GLA8094V Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS	Current Month Oct 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Oct 2013
9301009	Fairs, Shows, and Exhibits	-	-	-	-
9301010	Publicity	80	1,957	2,627	2,918
9301011	Dedications, Tours, & Openings	-	-	-	-
9301012	Public Opinion Surveys	8	25	52	80
9301014	Video Communications	-	5	7	7
9301015	Other Corporate Comm Exp	2,858	2,706	16,335	29,570
9302000	Misc General Expenses	(4,107)	5,936	75,773	147,756
9302003	Corporate & Fiscal Expenses	4,717	9,772	19,895	19,353
9302004	Research, Develop&Demonstr Exp	148	486	2,405	2,980
9302458	AEPSC Non Affliated expenses	0	0	1	89
9310000	Rents	-	-	1,363	1,363
9310001	Rents - Real Property	7,635	22,906	76,905	98,553
9310002	Rents - Personal Property	11,395	34,158	90,406	98,312
	Administration & General	**1,262,123**	**3,631,934**	**14,833,876**	**19,046,121**
	Accretion	-	-	-	-
4116000	Gain From Disposition of Plant	(295)	(885)	(2,946)	(3,464)
	Loss/(Gain) on Utility Plant	**(295)**	**(885)**	**(2,946)**	**(3,464)**
9302006	Assoc Bus Dev - Materials Sold	(18,807)	31,477	45,487	67,175
9302007	Assoc Business Development Exp	50,716	106,283	188,279	211,003
	Associated Business Development Expenses	**31,910**	**137,760**	**233,766**	**278,178**
4265009	Factored Cust A/R Exp - Affil	62,111	200,722	703,417	841,891
4265010	Fact Cust A/R-Bad Debts-Affil	98,736	281,902	950,679	1,151,485
	Opr Exp and Factored A/R	**160,847**	**482,624**	**1,654,096**	**1,993,376**
	Water Heaters	-	-	-	-
4171001	Exp of NonUtil Oper - Nonassoc	-	-	-	-
4265004	Social & Service Club Dues	790	13,560	49,152	58,628
	Expense of Non-Utility Operation	**790**	**13,560**	**49,152**	**58,628**
4210009	Misc Non-Op Exp - NonAssoc	639	1,974	9,086	10,787
	Misc NonOp Expenses - NonAssoc	**639**	**1,974**	**9,086**	**10,787**
4261000	Donations	18,489	79,424	236,509	306,444
	Donation Contributions	**18,489**	**79,424**	**236,509**	**306,444**
4263001	Penalties	2	3	3,046	3,046
	Provision for Penalties	**2**	**3**	**3,046**	**3,046**
4264000	Civic & Political Activities	17,917	46,559	205,339	275,181
	Civic & Political Activities	**17,917**	**46,559**	**205,339**	**275,181**
4265002	Other Deductions - Nonassoc	1,385	34,014,238	34,016,211	34,016,386
4265033	Ohio Merger - Transition Costs	251	6,305	17,366	17,366
	Other Deductions	**1,636**	**34,020,543**	**34,033,577**	**34,033,752**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**200,320**	**34,644,687**	**36,190,804**	**36,681,214**
	Operational Expenses	**5,018,110**	**48,523,697**	**82,392,214**	**95,137,739**
5100000	Maint Supv & Engineering	121,490	365,908	1,518,406	1,889,241
5110000	Maintenance of Structures	137,155	210,632	503,043	611,469
5120000	Maintenance of Boiler Plant	588,820	1,398,318	4,456,715	5,839,256
5120025	Maint of Blr Plt Environmental	-	(7)	-	(13)
5130000	Maintenance of Electric Plant	(1,316,104)	1,195,420	2,763,177	3,055,044
5140000	Maintenance of Misc Steam Plt	36,220	109,860	461,614	512,663
5140025	Maint MiscStmPlt Environmental	-	-	(2)	-
	Steam Generation Maintenance	**(432,419)**	**3,280,129**	**9,702,963**	**11,907,660**
5300000	Maint of Reactor Plant Equip	-	-	-	(1)
	Nuclear Generation Maintenance	-	-	-	**(1)**
	Hydro Generation Maintenance	-	-	-	-
	Other Generation Maintenance	-	-	-	-
5680000	Maint Supv & Engineering	7,477	19,484	87,926	115,895
5690000	Maintenance of Structures	(63)	409	10,444	13,722
5691000	Maint of Computer Hardware	1,824	8,134	17,226	25,973
5692000	Maint of Computer Software	18,430	88,666	232,979	296,071
5693000	Maint of Communication Equip	6,145	10,137	23,489	31,096
5700000	Maint of Station Equipment	81,835	246,028	582,428	594,969
5710000	Maintenance of Overhead Lines	91,369	719,448	1,439,667	2,153,124
5720000	Maint of Underground Lines	-	-	-	-
5730000	Maint of Misc Trnsmssion Plt	12,198	28,700	40,596	83,973
	Transmission Maintenance	**219,216**	**1,121,005**	**2,434,756**	**3,314,826**
5900000	Maint Supv & Engineering	(68)	297	1,036	1,052
5910000	Maintenance of Structures	11,784	13,291	24,904	29,279
5920000	Maint of Station Equipment	95,053	231,740	688,330	724,314
5930000	Maintenance of Overhead Lines	1,613,002	5,772,031	21,228,825	25,160,386

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5930001	Tree and Brush Control	33,126	95,189	312,419	387,631
5930010	Storm Expense Amortization	391,537	1,174,611	3,915,370	4,698,444
5930011	EMI Device Expense - Affiliate	-	-	-	-
5940000	Maint of Underground Lines	10,388	24,532	230,765	240,585
5950000	Maint of Lne Trnf Rglators&Dvi	9,097	23,398	47,648	52,009
5960000	Maint of Strt Lghtng & Sgnal S	3,896	12,331	51,995	61,690
5970000	Maintenance of Meters	4,251	13,977	44,904	57,377
5980000	Maint of Misc Distribution Plt	10,813	26,223	76,632	95,723
	Distribution Maintenance	**2,182,878**	**7,387,619**	**26,622,828**	**31,508,490**
9350000	Maintenance of General Plant	-	-	-	-
9350001	Maint of Structures - Owned	23,379	63,005	283,121	539,386
9350002	Maint of Structures - Leased	1,012	8,447	42,365	52,708
9350003	Maint of Prprty Held Fture Use	-	-	0	0
9350007	Maint of Radio Equip - Owned	-	-	-	-
9350013	Maint of Cmmncation Eq-Unall	79,511	225,566	667,182	805,410
9350015	Maint of Office Furniture & Eq	13,520	27,865	292,015	292,015
9350016	Maintenance of Video Equipment	-	-	654	654
9350019	Maint of Gen Plant-SCADA Equ	16	45	135	135
9350023	Site Communications Services	-	-	-	0
9350024	Maint of DA-AMI Comm Equip	251	5,926	6,261	6,343
	Administration & General Maintenance	**117,688**	**330,854**	**1,291,731**	**1,696,649**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**2,087,363**	**12,119,608**	**40,062,268**	**48,427,623**
	Total Maintenance and Operational Expenses	**7,106,473**	**60,643,304**	**122,444,482**	**143,565,361**
4211000	Gain on Dspsition of Property	-	2,143	(1,768,048)	(1,768,048)
	Gain on Disposition of Property	-	**2,143**	**(1,768,048)**	**(1,768,048)**
4212000	Loss on Dspsition of Property	-	-	7,425	7,425
	Loss on Disposition of Property	-	-	**7,425**	**7,425**
	Loss(Gain) of Sale of Property	-	**2,143**	**(1,760,623)**	**(1,760,623)**
	Memo: Operational and Sale of Property	*5,018,110*	*48,525,840*	*80,631,591*	*93,377,116*
4040001	Amort. of Plant	295,259	951,658	3,091,202	3,666,256
4060001	Amort of Plt Acq Adj	3,218	9,654	32,180	38,616
	DDA Amortization	**298,477**	**961,312**	**3,123,382**	**3,704,872**
4073000	Regulatory Debits	24,091	72,272	241,116	289,297
	DDA Regulatory Debits	**24,091**	**72,272**	**241,116**	**289,297**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**322,568**	**1,033,583**	**3,364,498**	**3,994,169**
4030001	Depreciation Exp	4,447,990	13,322,156	44,599,536	53,256,645
4030021	AEPSC Bell Howell Inserter	-	-	-	486
	DDA Depreciation	**4,447,990**	**13,322,156**	**44,599,536**	**53,257,131**
	DDA STP Nuclear Decommissioning	-	-	-	-
	DDA Asset Retirement Obligation	-	-	-	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**4,447,990**	**13,322,156**	**44,599,536**	**53,257,131**
	Depreciation and Amortization	**4,770,557**	**14,355,739**	**47,964,034**	**57,251,301**
408100800	State Franchise Taxes	-	-	-	-
408100810	State Franchise Taxes	-	-	-	-
408100811	State Franchise Taxes	-	-	-	(22,194)
408100812	State Franchise Taxes	-	-	-	-
408100813	State Franchise Taxes	-	-	3,782	3,782
	Franchise Taxes	-	-	**3,782**	**(18,412)**
408100600	State Gross Receipts Tax	-	-	71,358	71,358
408100608	State Gross Receipts Tax	-	(12,336)	(12,336)	(12,336)
408100609	State Gross Receipts Tax	-	(26,747)	(26,747)	(26,747)
408100610	State Gross Receipts Tax	-	-	-	-
408100611	State Gross Receipts Tax	-	-	-	-
408100612	State Gross Receipts Tax	-	-	(31,461)	(47,748)
408100613	State Gross Receipts Tax	5,000	(5,024)	58,973	58,973
	Revenue-kWhr Taxes	**5,000**	**(44,107)**	**69,787**	**43,500**
4081002	FICA	222,167	622,131	2,012,089	2,580,974
4081003	Federal Unemployment Tax	22	331	17,280	34,829
4081007	State Unemployment Tax	35	724	38,662	38,816
4081033	Fringe Benefit Loading - FICA	(94,646)	(247,145)	(818,805)	(1,108,690)
4081034	Fringe Benefit Loading - FUT	(662)	(1,857)	(6,909)	(8,440)

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4081035	Fringe Benefit Loading - SUT	(1,430)	(3,996)	(12,254)	(15,425)
	Payroll Taxes	**125,486**	**370,188**	**1,230,063**	**1,522,063**
	Capacity Taxes	-	-	-	-
408100506	Real & Personal Property Taxes	-	-	-	-
408100507	Real & Personal Property Taxes	-	-	-	-
408100508	Real & Personal Property Taxes	-	-	811	811
408100509	Real & Personal Property Taxes	-	-	-	-
408100510	Real Personal Property Taxes	-	15,358	52,599	(45,775)
408100511	Real Personal Property Taxes	-	275,371	18,710	1,619,375
408100512	Real Personal Property Taxes	828,286	2,484,856	8,283,051	8,283,051
408102908	Real/Pers Prop Tax-Cap Leases	-	-	-	-
408102909	Real/Pers Prop Tax-Cap Leases	-	-	-	-
408102910	Real-Pers Prop Tax-Cap Leases	-	-	-	(104,116)
408102911	Real-Pers Prop Tax-Cap Leases	-	6	(10,038)	(10,038)
408102912	Real-Pers Prop Tax-Cap Leases	(626)	237	(3,487)	(708)
408102913	Real-Pers Prop Tax-Cap Leases	1,443	4,329	14,430	14,430
408103608	Real Prop Tax-Cap Leases	-	-	-	-
408103609	Real Prop Tax-Cap Leases	-	-	-	-
408103610	Real Prop Tax-Cap Leases	-	-	-	-
408103611	Real Prop Tax-Cap Leases	-	-	-	-
408103612	Real Prop Tax-Cap Leases	-	-	-	4,245
408103613	Real Prop Tax-Cap Leases	2,250	6,750	22,500	22,500
408200509	Real & Personal Property Taxes	-	-	-	-
408200510	Real Personal Property Taxes	-	-	-	-
408200511	Real Personal Property Taxes	-	-	-	9,430
408200512	Real Personal Property Taxes	4,717	16,202	49,221	49,221
	Property Taxes	**836,070**	**2,803,108**	**8,427,796**	**9,842,424**
408101809	St Publ Serv Comm Tax/Fees	-	-	-	-
408101810	St Publ Serv Comm Tax-Fees	-	-	-	-
408101811	St Publ Serv Comm Tax-Fees	-	-	-	-
408101812	St Publ Serv Comm Tax-Fees	-	-	515,095	686,794
408101813	St Publ Serv Comm Tax-Fees	78,854	236,561	315,415	315,415
	Regulatory Fees	**78,854**	**236,561**	**830,510**	**1,002,208**
408101410	Federal Excise Taxes	-	-	-	-
408101411	Federal Excise Taxes	-	-	-	-
408101412	Federal Excise Taxes	-	-	-	-
408101413	Federal Excise Taxes	-	117	2,489	2,489
	Production Taxes	-	**117**	**2,489**	**2,489**
408101710	St Lic-Rgstrtion Tax-Fees	-	-	-	-
408101711	St Lic-Rgstrtion Tax-Fees	-	-	-	-
408101712	St Lic-Rgstrtion Tax-Fees	-	-	-	-
408101713	St Lic Rgstrtion Tax-Fees	-	60	60	60
408101900	State Sales and Use Taxes	-	336,570	336,570	336,570
408101909	State Sales and Use Taxes	-	-	-	-
408101910	State Sales and Use Taxes	-	-	-	-
408101911	State Sales and Use Taxes	-	-	-	-
408101912	State Sales and Use Taxes	-	-	1,109	3,102
408101913	State Sales and Use Taxes	807	2,351	9,605	9,605
408102210	Municipal License Fees	-	-	-	-
408102211	Municipal License Fees	-	-	-	-
408102212	Municipal License Fees	-	-	-	-
408102213	Municipal License Fees	-	125	325	325
	Miscellaneous Taxes	**807**	**339,106**	**347,868**	**349,662**
	Other Non-Income Taxes	**807**	**339,223**	**350,158**	**352,151**
	Taxes Other Than Income Taxes	**1,046,216**	**3,704,973**	**10,902,096**	**12,743,935**
	TOTAL OPERATING EXPENSES	**12,922,246**	**78,706,159**	**179,549,989**	**211,799,974**
	Memo: SEC Total Operating Expenses	**39,022,173**	**167,562,500**	**498,816,676**	**587,449,410**
	OPERATING INCOME	**7,929,796**	**(15,910,431)**	**42,811,466**	**58,974,309**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	1,858	11,439	204,556	208,454
	Interest & Dividend NonAffiliated	**1,858**	**11,439**	**204,556**	**208,454**
4190005	Interest Income - Assoc CBP	3,408	14,533	30,194	43,901
	Interest & Dividend Affiliated	**3,408**	**14,533**	**30,194**	**43,901**
	Total Interest & Dividend Income	**5,266**	**25,972**	**234,750**	**252,355**
4210039	Carrying Charges	5,985	18,328	65,353	79,857

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
11/08/2013 18:31

Oct 2013 / 09B V2099-01-01	Layout: GLA8094V / Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS	Current Month Oct 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Oct 2013
	Interest & Dividend Carrying Charge	**5,985**	**18,328**	**65,353**	**79,857**
	Memo: Total Interest & Dividend Income w/ Carrying	**11,251**	**44,300**	**300,103**	**332,212**
4191000	Allw Oth Fnds Usd Drng Cnstr	2,943	360,287	1,179,037	619,477
	AFUDC	**2,943**	**360,287**	**1,179,037**	**619,477**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
	Interest LTD IPC	-	-	-	-
4300001	Interest Exp - Assoc Non-CBP	87,500	262,500	875,000	1,050,000
	Interest LTD Notes Payable - Affiliated	**87,500**	**262,500**	**875,000**	**1,050,000**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	2,833,226	8,499,677	28,332,255	33,998,706
	Interest LTD Senior Unsecured	**2,833,226**	**8,499,677**	**28,332,255**	**33,998,706**
	Interest LTD Other - Affil	-	-	-	-
	Interest LTD Other - NonAffil	-	-	-	-
	Interest on Long-Term Debt	**2,920,726**	**8,762,177**	**29,207,255**	**35,048,706**
4300003	Int to Assoc Co - CBP	-	-	12,010	13,143
	Interest STD - Affil	-	-	**12,010**	**13,143**
4310007	Lines Of Credit	52,294	154,294	520,722	615,964
	Interest STD - NonAffil	**52,294**	**154,294**	**520,722**	**615,964**
	Interest on Short Term Debt	**52,294**	**154,294**	**532,731**	**629,107**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	39,266	117,797	392,655	471,186
	Amort of Debt Disc. Prem & Exp	**39,266**	**117,797**	**392,655**	**471,186**
4281004	Amrtz Loss Rcquired Debt-Dbnt	2,804	8,412	28,041	33,649
	Amort Loss on Reacquired Debt	**2,804**	**8,412**	**28,041**	**33,649**
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	776	2,258	22,658	24,077
4310002	Interest on Customer Deposits	3,415	10,866	35,247	39,777
4310022	Interest Expense - Federal Tax	-	(11,220)	(7,981)	12,874
4310023	Interest Expense - State Tax	-	46	3,347	4,310
	Other Interest - NonAffil	**4,191**	**1,951**	**53,271**	**81,037**
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	83	(243,404)	(812,491)	(406,178)
	AFUDC-Borrowed Funds	**83**	**(243,404)**	**(812,491)**	**(406,178)**
	Total Interest Charges	**3,019,383**	**8,801,226**	**29,401,462**	**35,855,508**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**4,924,628**	**(24,307,069)**	**14,889,144**	**24,070,491**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	11,844,908	948,478	4,873,611	2,707,336
4092001	Inc Tax, Oth Inc&Ded-Federal	(10,599,582)	641,670	1,188,291	1,151,625
	Federal Current Income Tax	**1,245,326**	**1,590,147**	**6,061,902**	**3,858,961**
4101001	Prov Def I/T Util Op Inc-Fed	1,831,198	8,106,661	32,481,653	59,124,668
4102001	Prov Def I/T Oth I&D - Federal	654	1,962	6,503	8,281
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(1,033,488)	(6,351,975)	(24,008,248)	(46,115,746)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(713,250)	(12,617,562)	(12,617,562)	(12,642,454)
	Federal Deferred Income Tax	**85,114**	**(10,860,913)**	**(4,137,654)**	**374,750**
4114001	ITC Adj, Utility Oper - Fed	(19,167)	(57,502)	(191,674)	(238,009)
	Federal Investment Tax Credits	**(19,167)**	**(57,502)**	**(191,674)**	**(238,009)**
	Federal Income Taxes	**1,311,272**	**(9,328,268)**	**1,732,674**	**3,995,701**
409100200	Income Taxes, UOI - State	-	-	-	-
409100207	Income Taxes, UOI - State	-	-	-	-
409100208	Income Taxes, UOI - State	-	-	-	-
409100210	Income Taxes UOI - State	-	-	-	-
409100211	Income Taxes UOI - State	-	-	-	(295,338)
409100212	Income Taxes UOI - State	-	-	-	270,728
409100213	Income Taxes UOI - State	2,033,802	514,194	2,267,844	2,267,844
409200210	Inc Tax Oth Inc Ded - State	-	-	-	-
409200211	Inc Tax Oth Inc Ded - State	-	-	-	(7,157)
409200212	Inc Tax Oth Inc Ded - State	-	-	-	156
409200213	Inc Tax Oth Inc Ded - State	(1,723,887)	104,359	193,260	193,260

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
11/08/2013 16:31
Oct 2013 Layout: GLA6094V
098 V2099-01-01 Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS

	Current Month Oct 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Oct 2013
State Current Income Tax	309,915	618,554	2,461,105	2,429,494
State Deferred Income Tax	-	-	-	-
State Investment Tax Credits	-	-	-	-
State Income Taxes	309,915	618,554	2,461,105	2,429,494
Local Current Income Tax	-	-	-	-
Local Deferred Income Tax	-	-	-	-
Local Investment Tax Credits	-	-	-	-
Local Income Taxes	-	-	-	-
Foreign Current Income Tax	-	-	-	-
Foreign Deferred Income Tax	-	-	-	-
Foreign Investment Tax Credits	-	-	-	-
Foreign Income Taxes	-	-	-	-
Total Income Taxes	1,621,187	(8,709,714)	4,193,679	6,425,195
Equity Earnings of Subs	-	-	-	-
INCOME AFTER INCOME TAXES and EQUITY EARNINGS	3,303,441	(15,597,354)	10,695,466	17,645,296
Discontinued Operations (Net of Taxes)	-	-	-	-
Cumulative Effect of Accounting Changes	-	-	-	-
Extraordinary Income / (Expenses)	-	-	-	-
NET INCOME	3,303,441	(15,597,354)	10,695,465	17,645,296

Kentucky Power Corp Consol
Comparative Balance Sheet
October 31, 2013

Run Date: 11/11/2013 13:45

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V
KYP_CORP_CI V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS

	Month End Balances 2013	December Balances Last Year	Variance $
ASSETS			
PRODUCTION	561,215,338.40	558,934,668.00	2,280,670.40
TRANSMISSION	495,877,680.05	490,152,082.00	5,725,598.05
DISTRIBUTION	682,386,682.37	652,615,328.83	29,771,353.54
GENERAL	61,519,951.15	57,451,300.18	4,068,650.97
CONSTRUCTION WORK IN PROGRESS	55,724,617.56	44,281,291.91	11,443,325.65
ELECTRIC UTILITY PLANT	**1,856,724,269.53**	**1,803,434,670.92**	**53,289,598.61**
less Accum Provision - Depre, Depl, Amort.	(655,417,474.70)	(624,238,902.51)	(31,178,572.19)
NET ELECTRIC UTILITY PLANT	**1,201,306,794.83**	**1,179,195,768.41**	**22,111,026.42**
Net NonUtility Property	2,685,168.50	5,498,717.60	(2,813,549.10)
Investment in Subsidiary & Associated	0.00	0.00	0.00
Other Investments	255,993.67	260,727.67	(4,734.00)
Other Special Funds	0.00	0.00	0.00
Allowance - NonCurrent	2,361,233.00	2,361,232.37	0.63
Long Term Energy Trading Contracts	4,059,953.89	6,881,654.77	(2,821,700.88)
OTHER PROPERTY AND INVESTMENTS	**9,362,349.06**	**15,002,332.41**	**(5,639,983.35)**
Cash and Cash Equivalents	807,066.56	1,925,747.09	(1,118,680.53)
Advances to Affiliates	12,624,778.92	0.00	12,624,778.92
Acct Rec - Customers	7,272,663.92	12,676,052.64	(5,403,388.72)
Acct Rec - Miscellaneous	2,443,641.76	3,141,697.43	(698,055.67)
Acct Rec - AP for Uncollectible Accounts	(84,974.86)	(141,538.08)	56,563.22
Acct Rec - Associated Companies	8,158,473.35	9,241,088.58	(1,082,615.23)
Fuel Stock	58,575,831.24	69,147,176.47	(10,571,345.23)
Materials and Supplies	20,298,346.97	25,061,279.42	(4,762,932.45)
Accrued Utility Revenues	(5,129,371.53)	816,939.53	(5,946,311.06)
Energy Trading	4,999,313.89	6,174,819.72	(1,175,505.83)
Prepayments	1,773,935.40	1,569,794.80	204,140.60
Other Current Assets	961,570.29	1,660,942.94	(699,372.65)
CURRENT ASSETS	**112,701,275.91**	**131,274,000.53**	**(18,572,724.62)**
REGULATORY ASSETS	**204,180,073.21**	**214,900,829.18**	**(10,720,755.97)**
TOTAL DEFERRED CHARGES	**43,932,336.28**	**78,498,798.33**	**(34,566,462.05)**
TOTAL ASSETS	**1,571,482,829.29**	**1,618,871,728.86**	**(47,388,899.57)**

Investment Accounts for Functional Property Split at October 2013 FINAL

Consol	Unit	Acct	PS Query	Production	Transmission	Distribution	General	Total
KEPCO	110	1010001	702,798,797.83	0.00	0.00	660,719,522.68	42,079,275.15	702,798,797.83
KEPCO	110	1011001	3,403,853.24	0.00	0.00	0.00	3,403,853.24	3,403,853.24
KEPCO	110	1011012	24,352.77	0.00	0.00	0.00	24,352.77	24,352.77
KEPCO	110	1050001	627,603.73	0.00	0.00	627,603.73	0.00	627,603.73
KEPCO	110	1060001	23,063,373.82	0.00	0.00	21,039,555.96	2,023,817.86	23,063,373.82
KEPCO	117	1010001	560,367,849.00	552,188,085.60	1,646,138.49	0.00	6,533,624.91	560,367,849.00
KEPCO	117	1011001	1,415,728.64	874,501.15	0.00	0.00	541,227.49	1,415,728.64
KEPCO	117	1011012	6,554.27	0.00	0.00	0.00	6,554.27	6,554.27
KEPCO	117	1050001	6,778,355.00	6,778,355.00	0.00	0.00	0.00	6,778,355.00
KEPCO	117	1060001	1,837,597.36	1,374,396.65	147.04	0.00	463,053.67	1,837,597.36
KEPCO	180	1010001	461,356,640.84	0.00	456,672,797.02	0.00	4,683,843.82	461,356,640.84
KEPCO	180	1011001	872,864.52	0.00	0.00	0.00	872,864.52	872,864.52
KEPCO	180	1011012	12,296.90	0.00	0.00	0.00	12,296.90	12,296.90
KEPCO	180	1050001	0.00	0.00	0.00	0.00	0.00	0.00
KEPCO	180	1060001	38,433,784.05	0.00	37,558,597.50	0.00	875,186.55	38,433,784.05
KEPCO Total			1,800,999,651.97	561,215,338.40	495,877,680.05	682,386,682.37	61,519,951.15	1,800,999,651.97

Preparer: Matthew Cowley, Property Accounting, Canton
Checker: Fred Francis, Property Accounting - Canton
Reviewer: Janet Swanger, Property Accounting, Canton
Sources of Information: Report GLA8300V, PowerPlant Asset - 1042 Report,
Leased Asset Management System Report and PeopleSoft GL Query

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Kentucky Power Corp Consol
Comparative Balance Sheet
October 31, 2013

Run Date: 11/11/2013 13:45

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V KYP_CORP_CI V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
CAPITALIZATION and LIABILITIES			
COMMON STOCK			
Authorized: 2,000,000 Shares			
Outstanding: 1,009,000 Shares			
Common Stock	50,450,000.00	50,450,000.00	0.00
Premium on Capital Stock	0.00	0.00	0.00
Paid-In-Capital	238,502,924.00	238,341,119.49	161,804.51
Retained Earnings	182,764,380.85	190,818,915.56	(8,054,534.72)
COMMON SHAREHOLDERS' EQUITY	**471,717,304.85**	**479,610,035.05**	(7,892,730.21)
PS Subject To Mandatory Redemption	0.00	0.00	0.00
PS Not Subject Mandatory Redemption	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK	**0.00**	**0.00**	**0.00**
TRUST PREFERRED SECURITIES	**0.00**	**0.00**	**0.00**
Long-Term Debt Less Amt Due 1 Yr	**549,360,887.50**	**549,221,950.00**	**138,937.50**
CAPITALIZATION	**1,021,078,192.35**	**1,028,831,985.05**	(7,753,792.71)
Obligations Under Capital Lease-NonCurrent	1,853,137.97	1,674,300.89	178,837.08
Accumulated Provision Rate Relief	0.00	1,635,430.00	(1,635,430.00)
Accumlated Provision - Miscellanous	33,929,249.33	34,033,794.12	(104,544.79)
Other NonCurrent Liabilities	**35,782,387.30**	**37,343,525.01**	(1,561,137.71)
Preferred Stock Due Within 1 Year	0.00	0.00	0.00
Long-Term Debt Due Within 1 Year	0.00	0.00	0.00
Accumulated Provision Due Within 1 Year	0.00	0.00	0.00
Short-Term Debt	0.00	0.00	0.00
Advances from Affiliates	0.00	13,358,855.63	(13,358,855.63)
A/P General	18,100,279.11	30,336,776.64	(12,236,497.53)
A/P Associated Companies	34,838,327.16	41,052,680.18	(6,214,353.02)
Customer Deposits	24,854,642.56	23,484,964.81	1,369,677.75
Taxes Accrued	3,369,950.58	6,548,714.64	(3,178,764.06)
Interest Accrued	7,933,282.23	7,166,695.02	766,587.21
Dividends Accrued	0.00	0.00	0.00
Obligation Under Capital Leases	1,133,560.67	1,403,875.95	(270,315.28)
Energy Contracts Current	2,275,058.68	3,320,068.02	(1,045,009.34)
Other Current and Accrued Liabilities	16,071,299.14	17,797,808.10	(1,726,508.96)
Current Liabilities	**108,576,400.13**	**144,470,438.99**	(35,894,038.87)
Deferred Income Taxes	**389,944,771.05**	**385,153,166.17**	**4,791,604.88**
Deferred Investment Tax Credits	**164,084.62**	**355,758.82**	(191,674.20)
Regulatory Liabilities	**9,488,710.72**	**13,831,965.72**	(4,343,255.00)
2440002 LT Unreal Losses - Non Affil	2,552,710.95	4,200,196.07	(1,647,485.12)

Kentucky Power Corp Consol
Comparative Balance Sheet
October 31, 2013

Run Date: 11/11/2013 13:45

X_OPR_COS KYP_CORP_CI	Rpt ID: GLR2200V Layout: GLR2200V V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
2440022	L/T Liability MTM Collateral	(158,754.00)	(582,545.00)	423,791.00
2450011	L/T Liability-Commodity Hedges	1,507.00	82,731.00	(81,224.00)
	Long-Term Energy Trading Contracts	2,395,463.95	3,700,382.07	(1,304,918.12)
2520000	Customer Adv for Construction	98,285.50	63,177.74	35,107.76
	Customer Advances for Construction	98,285.50	63,177.74	35,107.76
	Deferred Gains on Sale/Leaseback	0.00	0.00	0.00
	Deferred Gains on Dispostion of Utility Plant	0.00	0.00	0.00
2530000	Other Deferred Credits	0.00	0.00	0.00
2530022	Customer Advance Receipts	2,253,460.08	2,634,497.53	(381,037.45)
2530050	Deferred Rev -Pole Attachments	193,798.25	78,940.35	114,857.90
2530067	IPP - System Upgrade Credits	267,404.71	260,279.72	7,124.99
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	157,880.00	162,614.00	(4,734.00)
2530101	MACSS Unidentified EDI Cash	0.00	0.00	0.00
2530112	Other Deferred Credits-Curr	221,616.17	1,113,326.72	(891,710.55)
2530114	Federl Mitigation Deferal(NSR)	754,941.55	754,941.55	0.00
2530137	Fbr Opt Lns-Sold-Defd Rev	105,432.92	116,729.42	(11,296.50)
	Other Deferred Credits	3,954,533.68	5,121,329.29	(1,166,795.61)
	Deferred Credits	**6,448,283.13**	**8,884,889.10**	**(2,436,605.97)**
	DEFERRED CREDITS & REGULATED LIABILITIES	**406,045,849.52**	**408,225,779.81**	**(2,179,930.29)**
	CAPITAL & LIABILITIES	**1,571,482,829.30**	**1,618,871,728.87**	**(47,388,899.57)**

Kentucky Power Corp Consol
Comparative Balance Sheet
October 31, 2013

Run Date: 11/11/2013 13:45

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V KYP_CORP_CI V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS		Month End Balances 2013	December Balances Last Year	Variance $
	Statement of Retained Earnings			
	BALANCE AT BEGINNING OF YEAR	**190,818,915.56**	**171,840,462.36**	18,978,453.21
	Net Income (Loss)	10,695,465.28	50,978,453.21	(40,282,987.92)
	Deductions:			
	Dividend Declared On Common Stock	(18,750,000.00)	-32,000,000	13,250,000.00
	Dividend Declared On Preferred Stock	0.00	0	0.00
	Adjustment in Retained Earnings	0.00	0.00	0.00
	Total Deductions	(18,750,000.00)	(32,000,000.00)	13,250,000.00
	BALANCE AT END OF PERIOD (A)	**182,764,380.85**	**190,818,915.56**	(8,054,534.72)
	(A) Represents The Following Balances At End Of Period			
215.0	Appropriated Retained Earnings	0.00	0.00	0.00
215.1	Appr Retnd Erngs - Amrt Rsv, Fed	0.00	0.00	0.00
	Total Appropriated Retained Earnings	0.00	0.00	0.00
2160000-1	Unapprp Retained Earnings Unrestr	190,818,915.56	171,840,462.36	18,978,453.21
2160002+	Unapprp Retained Earnings Restr	0.00	0.00	0.00
210.0	Gain on Reacquired Pref Stock	0.00	0.00	0.00
	Net Income Transferred	(8,054,534.72)	18,978,453.21	(27,032,987.92)
	Total Unappropriated Retained Earnings	182,764,380.85	190,818,915.56	(8,054,534.72)
216.1	Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
418.1	Equity Earnings of Subsidiary Co	0.00	0.00	0.00
	Total Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
	Total Other Retained Earnings Accounts	0.00	0.00	0.00
	TOTAL RETAINED EARNINGS	**182,764,380.85**	**190,818,915.56**	(8,054,534.72)

Final

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - October, 2013

GLR7210V — 11/11/13 09:

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	559,731,713.30	5,401,870.86	(2,928,137.80)	0.00	0.00	562,205,446.36
	TOTAL PRODUCTION	559,731,713.30	5,401,870.86	(2,928,137.80)	0.00	0.00	562,205,446.36
101/106	TRANSMISSION	493,489,120.26	7,741,128.51	(1,439,823.88)	0.00	0.00	499,790,424.89
101/106	DISTRIBUTION	693,312,997.44	40,248,531.60	(7,699,357.39)	0.00	0.00	725,862,171.65
	TOTAL (ACCOUNTS 101 & 106)	1,746,533,831.00	53,391,530.97	(12,067,319.07)	0.00	0.00	1,787,858,042.90
1011001/12	CAPITAL LEASES	5,182,997.28	0.00	0.00	552,653.06	0.00	5,735,650.34
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	1,751,716,828.28	53,391,530.97	(12,067,319.07)	552,653.06	0.00	1,793,593,693.24
1050001	PLANT HELD FOR FUTURE USE	7,436,550.73	0.00	0.00	0.00	(30,592.00)	7,405,958.73
107000X	CONSTRUCTION WORK IN PROGRESS:						
107000X	BEG. BAL	44,281,291.91					
107000X	ADDITIONS		64,834,856.62				
107000X	TRANSFERS		(53,391,530.97)				
107000X	END BAL		11,443,325.65				55,724,617.56
	TOTAL ELECTRIC UTILITY PLANT	1,803,434,670.92	64,834,856.62	(12,067,319.07)	552,653.06	(30,592.00)	1,856,724,269.53
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	964,528.00	0.00	0.00	0.00	30,592.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,734,975.63	0.00	(2,834,483.00)	0.00	0.00	1,900,492.63
	TOTAL NONUTILITY PLANT	5,699,503.63	0.00	(2,834,483.00)	0.00	30,592.00	2,895,612.63

Prepared by: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee -- Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

Final

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - October, 2013

GLR7410V 11/11/13 09:

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	273,621,070.97	17,186,003.43	(2,928,137.80)	(1,421,399.35)	0.00	286,457,537.25
1080001/11	TRANSMISSION	157,337,333.70	7,272,660.86	(1,439,823.88)	301,955.13	0.00	163,472,125.81
1080001/11	DISTRIBUTION	179,721,144.51	20,303,583.27	(7,699,357.39)	(2,119,553.92)	0.00	190,205,816.47
1080013	PRODUCTION	(3,005,458.61)	0.00	0.00	0.00	(436,142.40)	(3,531,601.01)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(17,669.03)	0.00	0.00	0.00	(7,511.24)	(25,180.27)
	RETIREMENT WORK IN PROGRESS	(6,326,680.62)	0.00	0.00	(4,608,036.33)	3,238,998.14	(7,695,718.81)
	TOTAL (108X accounts)	**601,238,740.93**	**44,762,247.56**	**(12,067,319.07)**	**(8,047,034.47)**	**2,795,344.50**	**628,682,979.46**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,461,106.71	1,064,261.09	0.00	0.00	0.00	11,525,367.80
1110001	TRANSMISSION	1,266,854.71	426,638.48	0.00	0.00	0.00	1,693,493.19
1110001	DISTRIBUTION	9,166,379.72	1,600,302.84	0.00	0.00	0.00	10,766,682.56
	TOTAL (111X accounts)	**20,894,341.14**	**3,091,202.41**	**0.00**	**0.00**	**0.00**	**23,985,543.55**
1011006	CAPITAL LEASES	2,104,820.44	0.00	0.00	0.00	644,131.26	2,748,951.70
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**624,238,902.51**	**47,853,449.97**	**(12,067,319.07)**	**(8,047,034.47)**	**3,439,475.76**	**655,417,474.70**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	208,286.03	5,558.10	0.00	0.00	0.00	213,844.13
1240027	Other Property - RWIP	(7,500.00)	0.00	0.00	(2,834,483.00)	2,838,583.00	(3,400.00)
1240028	Other Property - RETIRE	0.00	0.00	(2,834,483.00)	2,834,483.00	0.00	0.00
	TOTAL NONUTILITY PLANT	**200,786.03**	**5,558.10**	**(2,834,483.00)**	**0.00**	**2,838,583.00**	**210,444.13**

Prepared By: PSnVision Report GLR7410V
Reviewer: Cindy Buckbee – Prop Acctg. Canton
Sources of Info: PowerPlant Reports and PS GL

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

November 25, 2013

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed Form EIA-826, Monthly Electric Utility Sales and Revenue Report with State Distributions for the month of October 2013.

Sincerely,

Bradley M. Funk

Bradley M. Funk
Manager –Regulated Accounting

BMF
Enclosure

U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue
Report with State Distributions – 2013

Form Approval
OMB NO 1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S W, Forrestal Building, Washington, D C 20585, and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D C 20503 (A person is required to respond to the collection of information only if it displays a valid OMB number) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**
Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650

Utility Name: Kentucky Power Company | **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan__ Feb__ Mar__ Apr__ May__ Jun__ Jul__ Aug__ Sep__ Oct X Nov__ Dec__, 2013

Contact Person: Ronald F Davis | **Phone number: 614-716-3525**

Email: rdavis@aep.com | **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a Revenue (Thousand Dollars)	$ 13,266	$ 11,287	$ 13,819		$ 38,372
	b Megwatthours	140,065	120,014	237,825		497,904
	c Number of consumers	139,665	30,757	1,303		171,725
	a Revenue (Thousand Dollars)					
	b Megwatthours					
	c Number of consumers					
	a Revenue (Thousand Dollars)					
	b Megwatthours					
	c Number of consumers					
	a Revenue (Thousand Dollars)					
	b Megwatthours					
	c Number of consumers					
	a Revenue (Thousand Dollars)					
	b Megwatthours					
	c Number of consumers					

Note

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

December 18, 2013

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed November 2013 Financial Report pages for Kentucky Power Company consisting of the following:

Page Nos.	Description
1-11	Income Statement
1-3	Details of Operating Revenues
4-8	Operating Expenses – Functional Expenses
8-11	Detail Statement of Taxes
12	Balance Sheet – Assets & Other Debits
13-14	Balance Sheet – Liabilities & Other Credits
13-14	Deferred Credits
15	Statement of Retained Earnings
16-17	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Bradley M. Funk

Bradley M. Funk
Manager –Regulated Accounting

BMF

Enclosure
Cc: Lila Munsey (w/pages)

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
12/09/2013 14:31
Nov 2013 — Layout: GLA8094V
09B V2099-01-01 — Account: GL_ACCT_SEC — Business Unit: GL_PRPT_CONS

Account		Description	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
		REVENUES				
4400001		Residential Sales-W/Space Htg	8,838,346	20,634,029	89,756,433	100,620,851
4400002		Residential Sales-W/O Space Ht	3,877,013	10,483,063	42,850,549	47,142,437
4400005		Residential Fuel Rev	5,578,929	13,127,141	59,629,806	65,939,070
	A	**Revenue - Residential Sales**	**18,294,288**	**44,244,232**	**192,236,788**	**213,702,358**
4420001		Commercial Sales	5,723,068	16,200,413	59,835,461	64,922,289
4420006		Sales to Pub Auth - Schools	1,087,161	3,199,525	10,909,742	11,882,359
4420007		Sales to Pub Auth - Ex Schools	1,087,898	3,042,931	11,259,736	12,186,283
4420013		Commercial Fuel Rev	3,318,243	9,373,200	36,306,249	39,043,064
	A	**Revenue - Commercial Sales**	**11,216,370**	**31,816,070**	**118,311,187**	**128,033,996**
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	4,747,883	13,831,416	50,791,375	53,558,463
4420004		Ind Sales-NonAffil(Incl Mines)	2,502,140	6,731,172	26,203,251	28,675,855
4420016		Industrial Fuel Rev	6,921,075	19,392,358	76,735,463	83,289,423
	A	**Revenue - Industrial Sales - NonAffiliated**	**14,171,097**	**39,954,946**	**153,730,090**	**165,523,741**
		Revenue - Industrial Sales	**14,171,097**	**39,954,946**	**153,730,090**	**165,523,741**
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	105,721	312,339	1,160,293	1,257,114
4440002		Public St & Hwy Light Fuel Rev	29,354	79,459	272,363	302,784
	A	**Revenue - Other Retail Sales**	**135,075**	**391,798**	**1,432,656**	**1,559,898**
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**43,816,830**	**116,407,046**	**465,710,721**	**508,819,991**
	B					
4561031		GFA Trans Base Rev Unb - Aff	-	-	-	-
4561032		GFA Trans Ancillary Rev - Aff	-	-	-	-
4561033		PJM NITS Revenue - Affiliated	3,136,640	9,531,097	33,321,167	36,480,417
4561034		PJM TO Adm Serv Rev - Aff	41,521	83,524	371,957	374,087
4561035		PJM Affiliated Trans NITS Cost	(3,086,734)	(9,369,240)	(32,653,897)	(35,707,078)
4561036		PJM Affiliated Trans TO Cost	(41,521)	(83,166)	(363,306)	(365,277)
4561059		Affil PJM Trans Enhancmnt Rev	27,832	83,590	258,018	278,147
4561060		Affil PJM Trans Enhancmnt Cost	(27,390)	(82,170)	(252,877)	(272,330)
4561062		PROVISION PJM NITS Affil- Cost	(63,826)	(191,161)	474,616	482,149
4561063		PROVISION PJM NITS Affiliated	(16,550)	(56,080)	(260,157)	(332,583)
	B	**Revenue - Transmission-Affiliated**	**(32,026)**	**(83,607)**	**895,521**	**937,532**
4470004		Sales for Resale-Nonaff-Ancill	-	-	-	-
4470005		Sales for Resale-Nonaff-Transm	-	-	-	-
4470150		Transm Rev.-Dedic Whlsl/Muni	2,205	6,386	42,747	49,529
4470206		PJM Trans loss credits-OSS	40,734	378,920	871,665	934,013
4470207		PJM transm loss charges - LSE	(655,896)	(855,410)	(7,199,839)	(8,068,309)
4470208		PJM Transm loss credits-LSE	150,258	149,436	1,561,654	1,699,008
4470209		PJM transm loss charges-OSS	(171,798)	(1,714,736)	(4,031,154)	(4,353,487)
4561002		RTO Formation Cost Recovery	1,264	2,277	5,018	7,418
4561003		PJM Expansion Cost Recov	7,507	21,553	76,935	84,926
4561004		SECA Transmission Rev	-	-	-	227,184
4561005		PJM Point to Point Trans Svc	46,035	152,519	557,060	624,207
4561006		PJM Trans Owner Admin Rev	20,128	60,451	201,534	219,004
4561007		PJM Network Integ Trans Svc	1,172,112	3,544,850	11,882,989	12,883,519
4561019		Oth Elec Rev Trans Non Affil	5,171	12,816	51,123	56,367
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	506	1,627	7,107	7,607
4561029		PJM NITS Revenue Whsl Cus-NAff	204,320	619,771	2,142,574	2,354,501
4561030		PJM TO Serv Rev Whls Cus-NAff	3,239	9,727	33,182	35,905
4561058		NonAffil PJM Trans Enhncmt Rev	27,435	82,213	225,880	240,253
4561061		NAff PJM RTEP Rev for Whsl-FR	1,812	5,435	16,608	17,958
4561064		PROVISION PJM NITS WhslCus-NAf	(1,187)	(3,562)	(17,532)	(21,839)
4561065		PROVISION PJM NITS	(6,504)	(19,079)	(71,497)	(83,576)
	A	**Revenue - Transmission-NonAffiliated**	**847,341**	**2,455,193**	**6,356,053**	**6,914,189**
		Revenue - Transmission	**815,314**	**2,371,586**	**7,251,575**	**7,851,720**
4210026		B/L Affil MTM Assign	-	-	-	-
4210028		Realized Affil Financial Assgn	-	-	-	-
4210045		UnReal Aff Fin Assign SNWA	-	-	-	-
4210046		Real Aff Fin Assign SNWA	-	-	-	-
4470001		Sales for Resale - Assoc Cos	1,463	5,022	8,946	8,421
4470035		Sls for Rsl - Fuel Rev - Assoc	20,936	36,605	101,845	106,120
4470128		Sales for Res-Aff Pool Energy	955,589	5,786,177	36,617,597	39,087,076
4560111		MTM Aff GL Coal Trading	-	-	-	-

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
12/09/2013 14 31

Nov 2013 09B V2099-01-01		Layout: GLA8094V Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
4560112		Realized GL Coal Trading-Affil	-	-	-	-
	B	**Revenue - Resale-Affiliated**	**977,988**	**5,827,804**	**36,728,388**	**39,201,617**
4210025		B/L MTM Assignments	-	-	-	-
4210027		Realized Financial Assignments	-	-	-	-
4210035		Gn/Ls MTM Emissions - Forwards	-	-	-	-
4210043		Realiz Sharing West Coast Pwr	-	-	15	15
4470002		Sales for Resale - NonAssoc	143,737	727,515	3,567,873	4,275,568
4470006		Sales for Resale-Bookout Sales	1,056,778	3,241,420	13,747,917	15,089,345
4470007		Sales for Resale-Option Sales	-	-	-	-
4470010		Sales for Resale-Bookout Purch	(674,119)	(2,135,204)	(9,611,391)	(10,527,775)
4470011		Sales for Resale-Option Purch	-	-	-	-
4470027		Whsal/Muni/Pb Ath Fuel Rev	198,976	659,615	2,503,353	2,791,313
4470028		Sale/Resale - NA - Fuel Rev	467,019	1,035,486	3,616,298	4,609,967
4470033		Whsal/Muni/Pub Auth Base Rev	197,989	543,046	1,624,827	1,883,275
4470066		PWR Trding Trans Exp-NonAssoc	(4)	(281)	(2,095)	(2,249)
4470081		Financial Spark Gas - Realized	40,083	118,858	426,444	464,774
4470082		Financial Electric Realized	(366,449)	(1,098,735)	(3,199,352)	(3,824,425)
4470089		PJM Energy Sales Margin	(48,772)	1,248,154	7,539,385	7,911,216
4470093		PJM Implicit Congestion-LSE	(277,085)	161,204	(3,602,500)	(3,863,482)
4470098		PJM Oper Reserve Rev-OSS	83,357	502,451	1,516,692	1,676,856
4470099		Capacity Cr Net Sales	37,553	115,670	414,530	451,958
4470100		PJM FTR Revenue-OSS	4,502	178,507	348,804	366,547
4470101		PJM FTR Revenue-LSE	177,001	219,432	2,604,894	2,840,079
4470103		PJM Energy Sales Cost	3,383,103	13,667,603	52,555,278	57,304,911
4470106		PJM Pt2Pt Trans Purch-NonAff	(1)	(48)	(1,312)	(1,403)
4470107		PJM NITS Purch-NonAff	(1,518)	(6,828)	(18,229)	(19,870)
4470109		PJM FTR Revenue-Spec	6,640	23,106	7,366	(7,888)
4470110		PJM TO Admin Exp -NonAff	(115)	(697)	(1,019)	(1,102)
4470112		Non-Trading Bookout Sales-OSS	-	-	(2,027)	36,273
4470115		PJM Meter Corrections-OSS	15,458	(1,392)	3,030	2,850
4470116		PJM Meter Corrections-LSE	23,881	(4,967)	48,947	56,278
4470124		PJM Incremental Spot-OSS	(0)	(0)	(0)	(0)
4470126		PJM Incremental Imp Cong-OSS	(97,146)	(1,304,811)	(2,998,040)	(3,086,762)
4470131		Non-Trading Bookout Purch-OSS	-	-	180	19
4470141		PJM Contract Net Charge Credit	-	62	-	(0)
4470143		Financial Hedge Realized	22,007	55,687	138,910	187,335
4470144		Realiz Sharing - 06 SIA	96	404	1,500	46
4470155		OSS Physical Margin Reclass	(101,430)	(335,717)	(1,169,818)	(1,532,137)
4470156		OSS Optim. Margin Reclass	101,430	335,717	1,169,818	1,532,137
4470167		MISO FTR Revenues OSS	-	-	-	-
4470168		Interest Rate Swaps-Power	(5,089)	(9,269)	(32,459)	(32,459)
4470169		Capacity Sales Trading	-	-	-	-
4470170		Non-ECR Auction Sales-OSS	277,893	807,476	4,739,735	5,336,758
4470174		PJM Whlse FTR Rev - OSS	6,688	14,983	108,532	130,631
4470175		OSS Sharing Reclass - Retail	(813,221)	(2,263,451)	(1,590,756)	(1,930,606)
4470176		OSS Sharing Reclass-Reduction	813,221	2,263,451	1,590,756	1,930,606
4470180		Trading intra-book Reclass	(4,523)	11,493	(5,395)	174
4470181		Auction intra-book Reclass	4,523	(11,493)	5,395	(174)
4470202		PJM OpRes-LSE-Credit	369,968	1,041,887	3,772,719	4,110,125
4470203		PJM OpRes-LSE-Charge	(234,246)	(546,717)	(1,768,075)	(2,031,285)
4470214		PJM 30m Suppl Reserve CR OSS	25	25,724	247,656	247,735
4470215		PJM 30m Suppl Reserve CH OSS	-	-	-	-
4470220		PJM Regulation - OSS	(535)	(2,242)	9,575	9,575
4470221		PJM Spinning Reserve - OSS	(1,533)	10,909	31,484	31,484
4470222		PJM Reasctive - OSS	35,057	105,685	379,594	379,594
4560016		Financial Trading Rev-Unreal	-	-	-	-
4560049		Merch Generation Finan -Realzd	-	-	(2)	(2)
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	4,193	2,918	34,477	5,045
5550080		PJM Hourly Net Purch -FERC	(549,448)	(2,266,918)	(8,424,984)	(9,306,673)
5550094		Purchased Power - Fuel	(31,263)	(155,512)	(491,637)	(526,684)
	A	**Revenue - Resale-NonAffiliated**	**4,264,682**	**16,974,181**	**69,836,893**	**76,967,517**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**5,242,670**	**22,801,985**	**106,565,281**	**116,169,133**
4540001		Rent From Elect Property - Af	21,851	65,553	240,361	262,865
	B	**Revenue - Other Ele-Affiliated**	**21,851**	**65,553**	**240,361**	**262,865**
4210049		Interest Rate Swaps-BTL Power	-	-	-	-
4210053		Specul Allow. Gains-SO2	-	-	-	-

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
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Nov 2013 / 09B V2099-01-01		Layout: GLA8094V / Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
4210054		Specul Allow Gains-Seas NOx	-	-	-	-
4265053		Specul Allow Loss-SO2	-	-	-	-
4265054		Specul Allow Loss-Seas NOx	-	-	-	-
4265056		Specul Allow Loss-CO2	-	-	-	-
4500000		Forfeited Discounts	200,679	726,494	3,055,203	3,307,057
4510001		Misc Service Rev - Nonaffil	23,211	83,544	359,486	377,438
4540002		Rent From Elect Property-NAC	28,739	46,039	99,642	99,792
4540005		Rent from Elec Prop-Pole Attch	440,099	1,317,226	5,491,781	5,921,738
4560007		Oth Elect Rev - DSM Program	387,812	1,216,831	2,806,631	3,082,676
4560012		Oth Elect Rev - Nonaffiliated	-	-	-	-
4560041		Miscellaneous Revenue-NonAffil	-	-	-	-
4560109		Interest Rate Swaps-Coal	-	-	-	-
		Revenue - Other Ele-NonAffiliated	**1,080,540**	**3,390,135**	**11,812,743**	**12,788,701**
		Revenue - Gas	-	-	-	-
4118002		Comp Allow Gains Title IV SO2	-	-	164	164
4118003		Comp Allow Gains-Seas NOx	8,550	16,316	26,316	26,316
4118004		Comp Allow Gains-Ann NOx	16,454	16,454	108,637	108,637
		Gain/(Loss) on Allowances	**25,004**	**32,770**	**135,118**	**135,118**
	A	**Revenue - Other Ele-NonAffiliated**	**1,105,544**	**3,422,905**	**11,947,861**	**12,923,818**
		Revenue - Other Opr Electric	**1,127,395**	**3,488,468**	**12,168,222**	**13,185,683**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	2,600	7,800	33,000	37,600
4180002		Non-Opratng Rntal Inc-Oper	-	-	-	(330)
4180003		Non-Opratng Rntal Inc-Maint	-	-	(772)	(772)
4180005		Non-Opratng Rntal Inc-Depr	(556)	(1,667)	(6,114)	(6,670)
	D	**Non-Operating Rental Income - NonAffiliated**	**2,044**	**6,133**	**26,114**	**29,828**
		Non-Operating Rental Income	**2,044**	**6,133**	**26,114**	**29,828**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210000		Misc Non-Operating Income	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	98	391	20,113	20,413
4210003		Misc Non-Op Inc-NonAscRoylty	-	-	-	-
4210005		Misc Non-Op Inc-NonAsc-Timber	-	19,302	36,616	36,616
4210007		Misc Non-Op Inc - NonAsc - Oth	69	196	10,868	12,385
	D	**Non-Operating Misc Income - NonAffiliated**	**167**	**19,889**	**67,597**	**69,414**
		Non-Operating Misc Income	**167**	**19,889**	**67,597**	**69,414**
4540004		Rent From Elect Prop-ABD-Nonaf	9,645	40,297	94,111	108,742
4560015		Other Electric Revenues - ABD	63,504	160,312	394,194	383,884
	D	**Associated Business Development Income**	**73,149**	**200,609**	**488,305**	**492,626**
		Revenue - Other Opr - Other	**75,360**	**226,631**	**582,016**	**591,867**
	=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
	=(D)	*Memo: Revenue-Oth Opr-Oth Non*	*75,360*	*226,631*	*582,016*	*591,867*
		Revenue - Other Operating	**1,202,756**	**3,715,088**	**12,770,238**	**13,778,550**
4491003		Prov Rate Refund - Retail	71,158	-	478,327	478,327
	A	**Provision for Rate Refund - NonAffiliated**	**71,158**	-	**478,327**	**478,327**
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	**71,168**	-	**478,327**	**478,327**
4210031		Pwr Sales Outside Svc Terrtry	-	-	1,267	1,267
4210032		Pwr Purch Outside Svc Terrtry	-	-	(539)	(539)
4210033		Mark to Mkt Out Svc Territory	-	-	-	-
	A	**Revenue - Power Sales**	-	-	**728**	**728**
		TOTAL OPERATING REVENUES	**51,148,727**	**145,295,705**	**592,776,869**	**647,098,451**
=(A)		*Memo: G/T/D Revenue*	*50,105,555*	*139,259,325*	*554,330,583*	*606,104,570*
=(B)		*Memo: Other Affiliated Revenue*	*967,812*	*5,809,750*	*37,864,271*	*40,402,013*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Non*	*75,360*	*226,631*	*582,016*	*591,867*
		Memo: Total Operating Revenues	*51,148,727*	*145,295,705*	*592,776,869*	*647,098,451*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***967,812***	*5,809,750*	*37,864,271*	*40,402,013*
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***50,180,915***	*139,485,955*	*554,912,599*	*606,696,437*
		Memo: Total Operating Revenues	*51,148,727*	*145,295,705*	*592,776,869*	*647,098,451*

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Account	Description	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
	FUEL EXPENSES				
5010000	Fuel	40,837	110,486	289,200	103,573
5010001	Fuel Consumed	1,406,854	5,075,856	79,887,746	85,354,810
5010003	Fuel - Procure Unload & Handle	55,476	185,687	2,505,172	2,658,426
5010012	Ash Sales Proceeds	-	-	(9,325)	(9,325)
5010013	Fuel Survey Activity	-	-	-	-
5010019	Fuel Oil Consumed	669,112	697,181	2,307,041	3,190,222
	Fuel Expense Total	**2,172,280**	**6,069,210**	**84,979,833**	**91,297,706**
5010005	Fuel - Deferred	(435,837)	(1,677,055)	(3,465,238)	(6,066,220)
	Deferred Fuel Expense	**(435,837)**	**(1,677,055)**	**(3,465,238)**	**(6,066,220)**
	Over Under Fuel Expense	-	-	-	-
	Fuel for Electric Generation	**1,736,443**	**4,392,156**	**81,514,596**	**85,231,486**
	Fuel from Affiliates for Electric Generation	-	-	-	-
5090000	Allow Consum Title IV SO2	174,723	593,841	4,854,116	5,289,379
5090002	Allowance Expenses	-	-	1	1
5090005	An NOx Cons Exp	1,193	3,781	12,097	18,385
	Allowances - Consumption	**175,916**	**597,622**	**4,866,214**	**5,307,765**
5020002	Urea Expense	227	609	1,748,462	1,850,029
5020003	Trona Expense	-	-	-	0
5020008	Activated Carbon	-	-	-	(22)
	Emissions Control - Chemicals	**227**	**609**	**1,748,462**	**1,850,007**
	Total Fuel for Electric Generation	**1,912,585**	**4,990,386**	**88,129,271**	**92,389,258**
	Memo: NonAff Fuel/Allow/Emissions	**1,912,585**	**4,990,386**	**88,129,271**	**92,389,258**
5550004	Purchased Power-Pool Capacity	2,631,078	7,798,440	25,393,005	27,433,987
5550005	Purchased Power - Pool Energy	7,686,463	23,173,900	70,771,654	78,421,361
5550027	Purch Pwr-Non-Fuel Portion-Aff	4,191,030	11,569,513	42,413,638	45,770,491
5550046	Purch Power-Fuel Portion-Affil	6,373,771	17,189,117	53,975,632	60,133,477
5550101	Purch Power-Pool Non-Fuel -Aff	1,381,714	3,433,389	9,842,906	10,817,702
5550102	Pur Power-Pool NonFuel-OSS-Aff	3,280,886	12,263,686	46,663,362	51,447,689
	Purchased Electricity from AEP - Affiliates	**25,544,942**	**75,428,045**	**249,060,197**	**274,024,707**
5550001	Purch Pwr-NonTrading-Nonassoc	287,827	441,977	1,116,644	1,127,127
5550023	Purch Power Capacity -NA	-	-	-	-
5550032	Gas-Conversion-Mone Plant	14,940	75,117	376,650	396,157
5550036	PJM Emer Energy Purch	-	-	-	-
5550039	PJM Inadvertent Mtr Res-OSS	(1,027)	(4,962)	(13,265)	(9,879)
5550040	PJM Inadvertent Mtr Res-LSE	(9,586)	(17,752)	(34,776)	(32,737)
5550041	PJM Ancillary Serv -Sync	-	(51)	2,494	2,793
5550074	PJM Reactive-Charge	571	1,706	6,155	6,800
5550075	PJM Reactive-Credit	9,475	28,443	102,700	111,770
5550076	PJM Black Start-Charge	272,012	882,823	3,794,228	3,798,121
5550077	PJM Black Start-Credit	(1,033)	(3,094)	(10,755)	(13,804)
5550078	PJM Regulation-Charge	69,217	228,904	1,227,723	1,346,378
5550079	PJM Regulation-Credit	(4,669)	(42,810)	(341,916)	(400,945)
5550083	PJM Spinning Reserve-Charge	12,401	21,893	57,244	58,067
5550084	PJM Spinning Reserve-Credit	(2,143)	(7,198)	(16,355)	(17,084)
5550090	PJM 30m Suppl Rserv Charge LSE	39	31,555	275,900	275,940
5550099	PJM Purchases-non-ECR-Auction	225,169	572,260	3,631,804	4,083,317
5550100	Capacity Purchases-Auction	7,226	21,691	76,569	79,011
5550107	Capacity purchases - Trading	8,695	27,653	172,817	199,518
	Purchased Electricity for Resale - NonAffiliated	**889,114**	**2,258,156**	**10,423,860**	**11,010,549**
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	**26,434,056**	**77,686,201**	**259,484,057**	**285,035,256**
	GROSS MARGIN	**22,802,086**	**62,619,119**	**246,163,542**	**269,673,937**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	155,772	443,419	1,594,348	1,883,219
5000001	Oper Super & Eng-RATA-Affil	-	-	28,000	28,000
5020000	Steam Expenses	46,936	203,110	728,876	852,162
5020025	Steam Exp Environmental	-	-	(7)	(15)
5050000	Electric Expenses	(3,542)	54,635	362,179	404,347
5060000	Misc Steam Power Expenses	299,724	798,443	3,456,899	3,924,837
5060001	Dresden Misc Steam Pwer Exp	-	4	4	4
5060002	Misc Steam Power Exp-Assoc	1,955	5,515	19,875	23,028
5060004	NSR Settlement Expense	(3,704)	(3,704)	(9,602)	(9,602)

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5060006	Voluntary CO2 Compliance Exp	-	-	-	-
5060025	Misc Stm Pwr Exp Environmental	3	(7)	16	16
5070000	Rents	-	-	900	900
	Steam Generation Op Exp	**497,145**	**1,501,415**	**6,181,487**	**7,106,897**
5170000	Oper Supervision & Engineering	-	-	1,074	1,074
	Nuclear Generation Op Exp	-	-	**1,074**	**1,074**
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	12,253	48,285	114,979	128,539
5570000	Other Expenses	104,785	351,543	1,187,960	1,346,098
5570007	Other Pwr Exp - Wholesale RECs	6,176	13,487	17,588	17,686
5570008	Other Pwr Exp - Voluntary RECs	-	-	-	-
5757000	PJM Admin-MAM&SC- OSS	15,004	77,297	293,695	300,800
5757001	PJM Admin-MAM&SC- Internal	49,283	141,035	611,207	693,257
	Other Generation Op Exp	**187,502**	**631,647**	**2,225,430**	**2,488,380**
5600000	Oper Supervision & Engineering	84,329	258,265	794,861	875,036
5610000	Load Dispatching	-	-	-	-
5611000	Load Dispatch - Reliability	1,211	2,557	8,802	9,633
5612000	Load Dispatch-Mntr&Op TransSys	78,987	211,883	742,755	822,639
5613000	Load Dispatch-Trans Srvc&Sched	-	-	-	-
5614000	PJM Admin-SSC&DS-OSS	14,672	74,390	286,346	293,459
5614001	PJM Admin-SSC&DS-Internal	47,266	134,778	608,802	691,914
5614007	RTO Admin Default LSE	(1,509)	(1,509)	(9,568)	(9,568)
5614008	PJM Admin Defaults OSS	-	-	-	-
5615000	Reliability,Plng&Stds Develop	10,722	42,904	138,020	155,356
5618000	PJM Admin-RP&SDS-OSS	3,352	15,786	61,330	62,828
5618001	PJM Admin-RP&SDS- Internal	11,281	30,041	145,312	162,559
5620001	Station Expenses - Nonassoc	46,953	100,233	237,811	256,445
5630000	Overhead Line Expenses	31,638	40,695	110,171	110,932
5640000	Underground Line Expenses	-	-	-	-
5650002	Transmssn Elec by Others-NAC	16,209	42,257	166,221	183,893
5650003	AEP Trans Equalization Agmt	-	-	-	-
5650012	PJM Trans Enhancement Charge	292,686	876,124	3,246,994	3,524,188
5650015	PJM TO Serv Exp - Aff	5,058	6,323	7,186	7,186
5650016	PJM NITS Expense - Affiliated	318,235	965,327	2,323,116	2,449,591
5650017	GFA Trans Exp Unb - Affiliate	-	-	-	-
5650018	PJM Trans Enhancement Credits	-	-	-	-
5650019	Affil PJM Trans Enhncement Exp	16,221	48,664	113,810	119,310
5650020	PROVISION PJM NITS Affl Expens	(30,639)	(70,470)	265,136	271,655
5660000	Misc Transmission Expenses	99,859	286,843	950,995	1,280,996
5670001	Rents - Nonassociated	-	-	6,339	6,339
5670002	Rents - Associated	-	-	-	151
5757002	SPP Admin-MAM&SC	-	0	0	0
	Transmission Op Exp	**1,046,531**	**3,066,090**	**10,206,440**	**11,274,540**
5800000	Oper Supervision & Engineering	52,940	152,196	642,591	676,100
5810000	Load Dispatching	245	788	2,918	3,251
5820000	Station Expenses	23,100	39,733	145,439	162,194
5830000	Overhead Line Expenses	90,478	186,054	510,864	545,951
5840000	Underground Line Expenses	7,336	29,271	122,051	128,977
5850000	Street Lighting & Signal Sys E	10,482	39,256	112,790	117,076
5860000	Meter Expenses	85,088	266,236	586,754	687,907
5870000	Customer Installations Exp	12,975	47,604	153,379	163,346
5880000	Miscellaneous Distribution Exp	370,737	949,851	3,653,867	4,518,099
5890001	Rents - Nonassociated	117,101	365,794	1,412,007	1,589,701
5890002	Rents - Associated	5,469	16,407	60,157	64,761
	Distribution Op Exp	**776,951**	**2,093,189**	**7,402,818**	**8,657,362**
9010000	Supervision - Customer Accts	25,479	75,130	267,121	295,329
9020000	Meter Reading Expenses	931	1,246	3,334	5,239
9020001	Customer Card Reading	-	-	-	0
9020002	Meter Reading - Regular	28,841	96,171	359,174	393,641
9020003	Meter Reading - Large Power	4,849	9,410	36,242	41,267
9020004	Read-In & Read-Out Meters	4,816	16,045	42,775	46,243
9030000	Cust Records & Collection Exp	29,436	81,711	312,672	371,008
9030001	Customer Orders & Inquiries	190,692	520,685	1,866,597	2,129,369
9030002	Manual Billing	3,785	9,317	31,853	36,991
9030003	Postage - Customer Bills	76,219	237,835	796,450	866,839
9030004	Cashiering	10,877	26,581	115,274	127,344
9030005	Collection Agents Fees & Exp	5,955	16,280	33,681	40,303
9030006	Credit & Oth Collection Activ	75,901	199,854	708,937	786,637
9030007	Collectors	59,408	152,561	531,861	596,576
9030009	Data Processing	13,338	42,454	149,785	166,548

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9040007	Uncoll Accts - Misc Receivable	(3,233)	62,749	(55,262)	86,403
9050000	Misc Customer Accounts Exp	1,767	4,789	18,630	19,907
9070000	Supervision - Customer Service	16,446	41,468	135,290	159,512
9070001	Supervision - DSM	-	-	(2)	(12)
9080000	Customer Assistance Expenses	44,006	131,776	440,493	490,130
9080001	DSM-Customer Advisory Grp	-	14	609	647
9080004	Cust Assistnce Exp - DSM - Ind	-	-	(1)	(1)
9080009	Cust Assistance Expense - DSM	306,208	979,877	2,606,640	2,789,807
9090000	Information & Instruct Advrtis	56,080	128,428	136,474	204,761
9100000	Misc Cust Svc&Informational Ex	9,529	11,937	31,415	36,368
9100001	Misc Cust Svc & Info Exp - RCS	-	-	-	-
	Customer Service and Information Op Exp	**961,329**	**2,846,318**	**8,570,061**	**9,690,855**
9110001	Supervision - Residential	-	-	-	-
9110002	Supervision - Comm & Ind	-	-	-	-
9120000	Demonstrating & Selling Exp	3,723	6,438	21,583	21,583
9120001	Demo & Selling Exp - Res	-	-	2	4
9120003	Demo & Selling Exp - Area Dev	26	26	26	25
	Sales Expenses	**3,749**	**6,464**	**21,610**	**21,612**
	Memo: Insurance (9240 9250)	**143,924**	**313,595**	**2,228,723**	**2,326,667**
9200000	Administrative & Gen Salaries	806,528	1,993,250	8,452,454	9,709,852
9200003	Admin & Gen Salaries Trnsfr	-	-	-	-
9210001	Off Supl & Exp - Nonassociated	56,352	178,162	1,174,230	961,297
9210003	Office Supplies & Exp - Trnsf	-	1	57	57
9210004	Office Utilites	-	-	-	-
9210005	Cellular Phones and Pagers	-	-	-	-
9220000	Administrative Exp Trnsf - Cr	(43,491)	(116,252)	(522,831)	(673,209)
9220001	Admin Exp Trnsf to Cnstrction	(36,707)	(122,852)	(507,834)	(554,644)
9220004	Admin Exp Trnsf to ABD	(3,445)	(3,623)	(7,654)	(8,485)
9220125	SSA Expense Transfers BL	-	-	-	(51,109)
9230001	Outside Svcs Empl - Nonassoc	140,555	472,823	2,101,492	2,467,349
9230003	AEPSC Billed to Client Co	4,378	(290,752)	(653,543)	46,986
9240000	Property Insurance	39,316	117,947	510,537	563,037
9250000	Injuries and Damages	93,215	279,645	1,002,566	1,097,368
9250001	Safety Dinners and Awards	321	520	1,787	1,874
9250002	Emp Accdent Prvntion-Adm Exp	120	2,422	10,552	11,777
9250004	Injuries to Employees	1,516	1,516	1,525	1,691
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	69,053	62,665	993,080	964,667
9250007	Prsnal Injries&Prop Dmage-Pub	1,577	18,089	81,968	83,273
9250010	Frg Ben Loading - Workers Comp	(61,193)	(169,408)	(373,293)	(397,031)
9260000	Employee Pensions & Benefits	10,326	11,032	14,443	14,819
9260001	Edit & Print Empl Pub-Salaries	820	2,435	9,274	13,509
9260002	Pension & Group Ins Admin	1,613	8,177	21,511	25,179
9260003	Pension Plan	338,160	1,014,479	3,719,757	3,990,169
9260004	Group Life Insurance Premiums	8,258	26,967	114,244	125,827
9260005	Group Medical Ins Premiums	256,415	796,990	3,384,770	3,663,316
9260006	Physical Examinations	0	1	28	28
9260007	Group L-T Disability Ins Prem	1,163	3,500	12,930	11,438
9260009	Group Dental Insurance Prem	18,320	56,941	216,166	234,150
9260010	Training Administration Exp	10	1,455	2,567	2,950
9260012	Employee Activities	819	3,412	5,453	5,592
9260014	Educational Assistance Pmts	-	-	4,761	5,466
9260021	Postretirement Benefits - OPEB	(125,025)	(375,074)	(1,375,270)	(1,255,061)
9260026	Savings Plan Administration	-	-	-	-
9260027	Savings Plan Contributions	164,162	392,248	1,273,532	1,435,292
9260036	Deferred Compensation	-	70,699	(1,406)	12,210
9260037	Supplemental Pension	325	974	3,570	3,631
9260050	Frg Ben Loading - Pension	(221,148)	(503,404)	(1,544,637)	(1,663,591)
9260051	Frg Ben Loading - Grp Ins	(230,139)	(533,676)	(1,812,586)	(1,983,386)
9260052	Frg Ben Loading - Savings	(76,593)	(171,603)	(527,286)	(602,172)
9260053	Frg Ben Loading - OPEB	42,905	105,091	71,963	(909)
9260055	IntercoFringeOffset- Don't Use	(121,776)	(279,319)	(866,000)	(954,576)
9260056	Fidelity Stock Option Admin	-	-	-	-
9260057	Postret Ben Medicare Subsidy	41,089	123,267	451,980	498,015
9260058	Frg Ben Loading - Accrual	180,645	95,062	(28,167)	16,491
9260060	Amort-Post Retirement Benefit	18,052	54,155	198,568	198,568
9270000	Franchise Requirements	11,429	34,439	130,518	142,719
9280000	Regulatory Commission Exp	25,382	25,676	26,740	26,733
9280001	Regulatory Commission Exp-Adm	2	(4)	2	(3)
9280002	Regulatory Commission Exp-Case	24,876	36,331	195,332	215,322
9301000	General Advertising Expenses	4,837	4,750	5,094	6,720

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
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Nov 2013 Layout: GLA8094V
098 V2099-01-01 Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS

Account	Description	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
9301001	Newspaper Advertising Space	1,144	1,524	21,259	28,196
9301002	Radio Station Advertising Time	4	12	46	636
9301003	TV Station Advertising Time	-	-	-	-
9301006	Spec Corporate Comm Info Proj	-	-	-	-
9301009	Fairs, Shows, and Exhibits	-	-	-	-
9301010	Publicity	88	1,925	2,715	2,876
9301011	Dedications, Tours, & Openings	-	-	-	-
9301012	Public Opinion Surveys	1,910	1,912	1,962	1,958
9301014	Video Communications	-	-	7	7
9301015	Other Corporate Comm Exp	7,134	9,993	23,470	32,292
9302000	Misc General Expenses	1,327	(5,095)	77,100	144,545
9302003	Corporate & Fiscal Expenses	(395)	7,419	19,499	19,450
9302004	Research, Develop&Demonstr Exp	494	753	2,899	3,123
9302458	AEPSC Non Affliated expenses	(0)	0	1	41
9310000	Rents	-	-	1,363	1,363
9310001	Rents - Real Property	7,635	22,906	84,540	92,360
9310002	Rents - Personal Property	12,243	34,977	102,650	106,611
	Administration & General	**1,476,604**	**3,607,679**	**16,310,479**	**18,846,659**
	Accretion	-	-	-	-
4116000	Gain From Disposition of Plant	(295)	(885)	(3,241)	(3,500)
	Loss/(Gain) on Utility Plant	**(295)**	**(885)**	**(3,241)**	**(3,500)**
9302006	Assoc Bus Dev - Materials Sold	(3,820)	(21,624)	41,667	63,244
9302007	Assoc Business Development Exp	43,461	140,937	231,740	245,723
	Associated Business Development Expenses	**39,641**	**119,313**	**273,406**	**308,967**
4265009	Factored Cust A/R Exp - Affil	64,600	185,440	768,016	835,833
4265010	Fact Cust A/R-Bad Debts-Affil	105,343	291,438	1,056,023	1,151,906
	Opr Exp and Factored A/R	**169,943**	**476,878**	**1,824,039**	**1,987,739**
	Water Heaters	-	-	-	-
4171001	Exp of NonUtil Oper - Nonassoc	-	-	-	-
4265004	Social & Service Club Dues	1,063	1,981	50,214	51,142
	Expense of Non-Utility Operation	**1,063**	**1,981**	**50,214**	**51,142**
4210009	Misc Non-Op Exp - NonAssoc	1,621	2,701	10,706	12,408
	Misc NonOp Expenses - NonAssoc	**1,621**	**2,701**	**10,706**	**12,408**
4261000	Donations	19,112	59,468	255,621	299,703
	Donation Contributions	**19,112**	**59,468**	**255,621**	**299,703**
4263001	Penalties	830	833	3,876	3,876
	Provision for Penalties	**830**	**833**	**3,876**	**3,876**
4264000	Civic & Political Activities	11,139	42,939	216,478	274,532
	Civic & Political Activities	**11,139**	**42,939**	**216,478**	**274,532**
4265002	Other Deductions - Nonassoc	1,678	34,015,550	34,017,889	34,018,161
4265033	Ohio Merger - Transition Costs	833	4,216	18,199	18,199
	Other Deductions	**2,511**	**34,019,766**	**34,036,088**	**34,036,360**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**206,218**	**34,604,565**	**36,397,022**	**36,665,759**
	Operational Expenses	**5,194,374**	**48,374,794**	**87,586,588**	**95,058,605**
5100000	Maint Supv & Engineering	101,412	341,140	1,619,818	1,862,073
5110000	Maintenance of Structures	50,339	217,217	553,382	600,799
5120000	Maintenance of Boiler Plant	964,235	1,968,779	5,420,950	6,079,585
5120025	Maint of Blr Plt Environmental	-	(9)	-	-
5130000	Maintenance of Electric Plant	86,350	(253,612)	2,849,527	2,962,368
5140000	Maintenance of Misc Steam Plt	27,071	96,133	488,685	513,513
5140025	Maint MiscStmPlt Environmental	-	-	(2)	-
	Steam Generation Maintenance	**1,229,406**	**2,369,649**	**10,932,359**	**12,018,338**
5300000	Maint of Reactor Plant Equip	-	-	-	(1)
	Nuclear Generation Maintenance	-	-	-	**(1)**
	Hydro Generation Maintenance	-	-	-	-
	Other Generation Maintenance	-	-	-	-
5680000	Maint Supv & Engineering	8,778	21,771	96,704	114,682
5690000	Maintenance of Structures	361	(484)	10,805	12,942
5691000	Maint of Computer Hardware	1,620	4,883	18,847	23,244
5692000	Maint of Computer Software	20,156	54,779	253,135	297,902
5693000	Maint of Communication Equip	(256)	7,054	23,232	26,988
5700000	Maint of Station Equipment	110,668	298,800	693,096	748,729
5710000	Maintenance of Overhead Lines	104,310	343,963	1,543,978	1,841,172
5720000	Maint of Underground Lines	-	-	-	-
5730000	Maint of Misc Trnsmssion Plt	21,643	42,105	62,239	70,572
	Transmission Maintenance	**267,280**	**772,872**	**2,702,036**	**3,136,231**

COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Application Of Kentucky Power Company For	)	
A General Adjustment Of Its Rates For Electric	)	
Service; (2) An Order Approving Its 2014	)	
Environmental Compliance Plan; (3) An Order	)	Case No. 2014-00396
Approving Its Tariffs And Riders; And (4) An	)	
Order Granting All Other Required Approvals	)	
And Relief	)	

SECTION II

FILING REQUIREMENTS

VOLUME 5 OF 5

December 23, 2014

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
12/09/2013 14:31

Nov 2013 / 09B V2009-01-01	Layout: GLA8094V / Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
5900000	Maint Supv & Engineering	63	314	1,100	1,092
5910000	Maintenance of Structures	412	12,341	25,315	29,031
5920000	Maint of Station Equipment	51,991	185,627	740,321	784,692
5930000	Maintenance of Overhead Lines	1,796,337	5,527,277	23,025,162	25,457,657
5930001	Tree and Brush Control	33,637	96,335	346,057	388,113
5930010	Storm Expense Amortization	391,537	1,174,611	4,306,907	4,698,444
5930011	EMI Device Expense - Affiliate	-	-	-	-
5940000	Maint of Underground Lines	883	19,586	231,646	240,994
5950000	Maint of Lne Trnf,Rglators&Dvi	5,482	24,600	53,131	54,200
5960000	Maint of Strt Lghtng & Sgnal S	6,615	13,122	58,610	64,915
5970000	Maintenance of Meters	6,673	15,178	51,576	57,916
5980000	Maint of Misc Distribution Plt	31,064	50,942	107,696	117,763
	Distribution Maintenance	**2,324,694**	**7,119,933**	**28,947,523**	**31,894,817**
9350000	Maintenance of General Plant	-	-	-	-
9350001	Maint of Structures - Owned	25,012	66,266	308,133	523,198
9350002	Maint of Structures - Leased	6,366	9,569	48,731	53,271
9350003	Maint of Prprty Held Fture Use	-	-	0	0
9350007	Maint of Radio Equip - Owned	-	-	-	-
9350013	Maint of Cmmncation Eq-Unall	65,937	209,836	733,119	817,045
9350015	Maint of Office Furniture & Eq	16,599	36,256	308,613	308,613
9350016	Maintenance of Video Equipment	-	-	654	654
9350019	Maint of Gen Plant-SCADA Equ	16	46	150	150
9350023	Site Communications Services	-	-	-	-
9350024	Maint of DA-AMI Comm Equip	25	3,311	6,286	6,286
	Administration & General Maintenance	**113,954**	**325,286**	**1,405,665**	**1,709,217**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**3,936,335**	**10,587,736**	**43,987,603**	**48,758,603**
	Total Maintenance and Operational Expenses	**9,129,709**	**58,962,532**	**131,574,191**	**143,817,208**
4211000	Gain on Dspsition of Property	-	-	(1,768,048)	(1,768,048)
	Gain on Disposition of Property	-	-	**(1,768,048)**	**(1,768,048)**
4212000	Loss on Dspsition of Property	-	-	7,425	7,425
	Loss on Disposition of Property	-	-	**7,425**	**7,425**
	Loss(Gain) of Sale of Property	-	-	**(1,760,623)**	**(1,760,623)**
	Memo: Operational and Sale of Property	*5,194,374*	*48,374,794*	*85,825,965*	*93,297,982*
4040001	Amort. of Plant	324,088	941,733	3,415,290	3,701,411
4060001	Amort of Plt Acq Adj	3,218	9,654	35,398	38,616
	DDA Amortization	**327,306**	**951,387**	**3,450,688**	**3,740,027**
4073000	Regulatory Debits	24,091	72,272	265,206	289,297
	DDA Regulatory Debits	**24,091**	**72,272**	**265,206**	**289,297**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**351,396**	**1,023,659**	**3,715,894**	**4,029,324**
4030001	Depreciation Exp	4,467,920	13,359,020	49,067,456	53,436,633
4030021	AEPSC Bell Howell Inserter	-	-	-	243
	DDA Depreciation	**4,467,920**	**13,359,020**	**49,067,456**	**53,436,876**
	DDA STP Nuclear Decommissioning	-	-	-	-
	DDA Asset Retirement Obligation	-	-	-	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**4,467,920**	**13,359,020**	**49,067,456**	**53,436,876**
	Depreciation and Amortization	**4,819,316**	**14,382,679**	**52,783,351**	**57,466,200**
408100800	State Franchise Taxes	-	-	-	-
408100809	State Franchise Taxes	-	-	-	-
408100810	State Franchise Taxes	-	-	-	-
408100811	State Franchise Taxes	-	-	-	(22,194)
408100812	State Franchise Taxes	(9,120)	(9,120)	(9,120)	(9,120)
408100813	State Franchise Taxes	-	-	3,782	3,782
	Franchise Taxes	**(9,120)**	**(9,120)**	**(5,338)**	**(27,532)**
408100600	State Gross Receipts Tax	-	-	71,358	71,358
408100608	State Gross Receipts Tax	-	(12,336)	(12,336)	(12,336)
408100609	State Gross Receipts Tax	-	(26,747)	(26,747)	(26,747)
408100610	State Gross Receipts Tax	-	-	-	-
408100611	State Gross Receipts Tax	-	-	-	-
408100612	State Gross Receipts Tax	-	-	(31,461)	(20,461)
408100613	State Gross Receipts Tax	(9,602)	398	49,371	49,371
	Revenue-kWhr Taxes	**(9,602)**	**(38,685)**	**50,185**	**61,185**

Kentucky Power Corp Consol
Comparative Income Statement

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Nov 2013 / 098 V2099-01-01	Layout: GLA8094V / Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
4081002	FICA	226,551	647,291	2,238,639	2,551,356
4081003	Federal Unemployment Tax	83	129	17,364	34,859
4081007	State Unemployment Tax	163	324	38,825	38,872
4081033	Fringe Benefit Loading - FICA	(140,006)	(311,570)	(958,811)	(1,096,018)
4081034	Fringe Benefit Loading - FUT	(979)	(2,251)	(7,888)	(8,553)
4081035	Fringe Benefit Loading - SUT	(2,101)	(4,841)	(14,355)	(15,730)
	Payroll Taxes	**83,711**	**329,081**	**1,313,774**	**1,504,787**
	Capacity Taxes	-	-	-	-
408100506	Real & Personal Property Taxes	-	-	-	-
408100507	Real & Personal Property Taxes	-	-	-	-
408100508	Real & Personal Property Taxes	-	-	811	811
408100509	Real & Personal Property Taxes	-	-	-	-
408100510	Real Personal Property Taxes	-	-	52,599	52,599
408100511	Real Personal Property Taxes	-	-	18,710	819,047
408100512	Real Personal Property Taxes	828,285	2,484,856	9,111,336	9,111,336
408102908	Real/Pers Prop Tax-Cap Leases	-	-	-	-
408102909	Real/Pers Prop Tax-Cap Leases	-	-	-	-
408102910	Real-Pers Prop Tax-Cap Leases	-	-	-	(104,116)
408102911	Real-Pers Prop Tax-Cap Leases	-	-	(10,038)	(10,038)
408102912	Real-Pers Prop Tax-Cap Leases	-	237	(3,487)	(2,100)
408102913	Real-Pers Prop Tax-Cap Leases	1,443	4,329	15,873	15,873
408103608	Real Prop Tax-Cap Leases	-	-	-	-
408103609	Real Prop Tax-Cap Leases	-	-	-	-
408103610	Real Prop Tax-Cap Leases	-	-	-	-
408103611	Real Prop Tax-Cap Leases	-	-	-	-
408103612	Real Prop Tax-Cap Leases	-	-	-	1,995
408103613	Real Prop Tax-Cap Leases	2,250	6,750	24,750	24,750
408200509	Real & Personal Property Taxes	-	-	-	-
408200510	Real Personal Property Taxes	-	-	-	-
408200511	Real Personal Property Taxes	-	-	-	4,713
408200512	Real Personal Property Taxes	4,717	16,202	53,938	53,938
	Property Taxes	**836,695**	**2,512,373**	**9,264,491**	**9,968,806**
408101809	St Publ Serv Comm Tax/Fees	-	-	-	-
408101810	St Publ Serv Comm Tax-Fees	-	-	-	-
408101811	St Publ Serv Comm Tax-Fees	-	-	-	-
408101812	St Publ Serv Comm Tax-Fees	-	-	515,095	600,944
408101813	St Publ Serv Comm Tax-Fees	78,854	236,561	394,268	394,268
	Regulatory Fees	**78,854**	**236,561**	**909,364**	**995,213**
408101410	Federal Excise Taxes	-	-	-	-
408101411	Federal Excise Taxes	-	-	-	-
408101412	Federal Excise Taxes	-	-	-	-
408101413	Federal Excise Taxes	-	-	2,489	2,489
	Production Taxes	-	-	**2,489**	**2,489**
408101710	St Lic-Rgstrtion Tax-Fees	-	-	-	-
408101711	St Lic-Rgstrtion Tax-Fees	-	-	-	-
408101712	St Lic-Rgstrtion Tax-Fees	-	-	-	-
408101713	St Lic Rgstrtion Tax-Fees	-	25	60	60
408101900	State Sales and Use Taxes	5,900	5,900	342,470	342,470
408101909	State Sales and Use Taxes	-	-	-	-
408101910	State Sales and Use Taxes	-	-	-	-
408101911	State Sales and Use Taxes	-	-	-	-
408101912	State Sales and Use Taxes	-	-	1,109	2,312
408101913	State Sales and Use Taxes	717	2,278	10,322	10,322
408102210	Municipal License Fees	-	-	-	-
408102211	Municipal License Fees	-	-	-	-
408102212	Municipal License Fees	-	-	-	-
408102213	Municipal License Fees	-	-	325	325
408201410	St Lic-Registration Tax-Fees	-	-	-	-
	Miscellaneous Taxes	**6,617**	**8,203**	**354,286**	**355,489**
	Other Non-Income Taxes	**6,617**	**8,203**	**356,775**	**357,978**
	Taxes Other Than Income Taxes	**987,155**	**3,038,413**	**11,889,250**	**12,860,437**
	TOTAL OPERATING EXPENSES	**14,936,180**	**76,383,624**	**194,486,169**	**212,383,222**
	Memo: SEC Total Operating Expenses	**43,282,821**	**159,060,210**	**542,099,497**	**589,807,736**
	OPERATING INCOME	**7,865,907**	**(13,784,505)**	**50,677,373**	**57,290,714**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	(88,247)	(78,664)	116,309	118,279

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
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Nov 2013 09B V2009-01-01	Layout: GLA8094V Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
	Interest & Dividend NonAffiliated	**(88,247)**	**(78,664)**	**116,309**	**118,279**
4190005	Interest Income - Assoc CBP	3,462	11,958	33,657	35,813
	Interest & Dividend Affiliated	**3,462**	**11,958**	**33,657**	**35,813**
	Total Interest & Dividend Income	**(84,784)**	**(66,706)**	**149,966**	**154,092**
4210039	Carrying Charges	5,860	17,955	71,213	78,407
	Interest & Dividend Carrying Charge	**5,860**	**17,955**	**71,213**	**78,407**
	Memo: Total Interest & Dividend Income w/ Carrying	**(78,924)**	**(48,750)**	**221,179**	**232,499**
4191000	Allw Oth Fnds Usd Drng Cnstr	140,090	323,832	1,319,127	634,341
	AFUDC	**140,090**	**323,832**	**1,319,127**	**634,341**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
	Interest LTD IPC	-	-	-	-
4300001	Interest Exp - Assoc Non-CBP	87,500	262,500	962,500	1,050,000
	Interest LTD Notes Payable - Affiliated	**87,500**	**262,500**	**962,500**	**1,050,000**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	2,833,226	8,499,677	31,165,481	33,998,706
	Interest LTD Senior Unsecured	**2,833,226**	**8,499,677**	**31,165,481**	**33,998,706**
	Interest LTD Other - Affil	-	-	-	-
	Interest LTD Other - NonAffil	-	-	-	-
	Interest on Long-Term Debt	**2,920,726**	**8,762,177**	**32,127,981**	**35,048,706**
4300003	Int to Assoc Co - CBP	-	-	12,010	13,143
	Interest STD - Affil	-	-	**12,010**	**13,143**
4310007	Lines Of Credit	49,772	151,024	570,494	619,340
	Interest STD - NonAffil	**49,772**	**151,024**	**570,494**	**619,340**
	Interest on Short Term Debt	**49,772**	**151,024**	**582,503**	**632,483**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	39,266	117,797	431,921	471,186
	Amort of Debt Disc. Prem & Exp	**39,266**	**117,797**	**431,921**	**471,186**
4281004	Amrtz Loss Rcquired Debt-Dbnt	2,804	8,412	30,845	33,649
	Amort Loss on Reacquired Debt	**2,804**	**8,412**	**30,845**	**33,649**
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	775	2,261	23,433	24,139
4310002	Interest on Customer Deposits	3,321	10,801	38,568	41,500
4310022	Interest Expense - Federal Tax	-	-	(7,981)	12,874
4310023	Interest Expense - State Tax	1,117	1,163	4,464	5,427
	Other Interest - NonAffil	**5,213**	**14,226**	**58,484**	**83,940**
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(100,625)	(224,282)	(913,117)	(423,282)
	AFUDC-Borrowed Funds	**(100,625)**	**(224,282)**	**(913,117)**	**(423,282)**
	Total Interest Charges	**2,917,154**	**8,829,353**	**32,316,617**	**35,846,682**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**5,009,918**	**(22,318,776)**	**19,899,062**	**22,310,672**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	(1,280,614)	(1,104,491)	3,592,997	(196,611)
4092001	Inc Tax, Oth Inc&Ded-Federal	4,044	662,594	1,192,336	1,183,826
	Federal Current Income Tax	**(1,276,570)**	**(441,897)**	**4,785,332**	**987,215**
4101001	Prov Def I/T Util Op Inc-Fed	13,042,213	18,874,736	45,523,865	58,670,177
4102001	Prov Def I/T Oth I&D - Federal	28,941	30,249	35,443	36,097
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(7,378,514)	(11,451,005)	(31,386,762)	(40,748,856)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(40,807)	(12,658,369)	(12,658,369)	(12,673,798)
	Federal Deferred Income Tax	**5,651,832**	**(5,204,388)**	**1,514,178**	**5,283,621**
4114001	ITC Adj, Utility Oper - Fed	(19,167)	(57,502)	(210,842)	(234,010)
	Federal Investment Tax Credits	**(19,167)**	**(57,502)**	**(210,842)**	**(234,010)**
	Federal Income Taxes	**4,356,095**	**(5,703,788)**	**6,088,668**	**6,036,826**
409100200	Income Taxes, UOI - State	-	-	-	-
409100207	Income Taxes, UOI - State	-	-	-	-
409100208	Income Taxes, UOI - State	-	-	-	-
409100209	Income Taxes, UOI - State	-	-	-	-
409100210	Income Taxes UOI - State	-	-	-	-
409100211	Income Taxes UOI - State	-	-	-	-

Kentucky Power Corp Consol
Comparative Income Statement

KYP_CORP_CONSOL
12/09/2013 14:31

Nov 2013 / 09B V2099-01-01	Layout: GLA8094V / Account: GL_ACCT_SEC Business Unit: GL_PRPT_CONS	Current Month Nov 2013	3 Mo Rolling 2013	Year-to-Date 2013	12mo Rolling Nov 2013
409100212	Income Taxes UOI - State	(175,242)	(175,242)	(175,242)	(555,889)
409100213	Income Taxes UOI - State	387,991	636,335	2,655,835	2,655,835
409200209	Inc Tax, Oth Inc & Ded - State	-	-	-	-
409200210	Inc Tax Oth Inc Ded - State	-	-	-	-
409200211	Inc Tax Oth Inc Ded - State	-	-	-	-
409200212	Inc Tax Oth Inc Ded - State	(4,867)	(4,867)	(4,867)	(6,510)
409200213	Inc Tax Oth Inc Ded - State	16,588	123,693	209,848	209,848
	State Current Income Tax	**224,470**	**579,919**	**2,685,575**	**2,303,285**
	State Deferred Income Tax	-	-	-	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	**224,470**	**579,919**	**2,685,575**	**2,303,285**
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	**4,580,565**	**(5,123,869)**	**8,774,243**	**8,340,111**
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**429,353**	**(17,194,908)**	**11,124,818**	**13,970,761**
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	**429,353**	**(17,194,908)**	**11,124,818**	**13,970,761**
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	**429,353**	**(17,194,908)**	**11,124,818**	**13,970,761**

Kentucky Power Corp Consol
Comparative Balance Sheet
November 30, 2013

Run Date: 12/10/2013 14:56

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V
KYP_CORP_C V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS

	Month End Balances 2013	December Balances Last Year	Variance $
ASSETS			
PRODUCTION	561,361,847.74	558,934,668.00	2,427,179.74
TRANSMISSION	497,193,758.87	490,152,082.00	7,041,676.87
DISTRIBUTION	688,421,711.63	652,615,328.83	35,806,382.80
GENERAL	56,659,967.45	57,451,300.18	(791,332.73)
CONSTRUCTION WORK IN PROGRESS	56,045,464.54	44,281,291.91	11,764,172.63
ELECTRIC UTILITY PLANT	**1,859,682,750.23**	**1,803,434,670.92**	**56,248,079.31**
less Accum Provision - Depre, Depl, Amort.	(653,765,682.34)	(624,238,902.51)	(29,526,779.83)
NET ELECTRIC UTILITY PLANT	**1,205,917,067.89**	**1,179,195,768.41**	**26,721,299.48**
Net NonUtility Property	2,684,612.69	5,498,717.60	(2,814,104.91)
Investment in Subsidiary & Associated	0.00	0.00	0.00
Other Investments	255,519.67	260,727.67	(5,208.00)
Other Special Funds	0.00	0.00	0.00
Allowance - NonCurrent	2,361,233.00	2,361,232.37	0.63
Long Term Energy Trading Contracts	3,745,516.81	6,881,654.77	(3,136,137.96)
OTHER PROPERTY AND INVESTMENTS	**9,046,882.17**	**15,002,332.41**	**(5,955,450.24)**
Cash and Cash Equivalents	513,527.03	1,925,747.09	(1,412,220.06)
Advances to Affiliates	11,884,571.46	0.00	11,884,571.46
Acct Rec - Customers	11,079,910.44	12,676,052.64	(1,596,142.20)
Acct Rec - Miscellaneous	2,684,555.33	3,141,697.43	(457,142.10)
Acct Rec - AP for Uncollectible Accounts	(77,561.68)	(141,538.08)	63,976.40
Acct Rec - Associated Companies	6,713,943.26	9,241,088.58	(2,527,145.32)
Fuel Stock	64,165,493.37	69,147,176.47	(4,981,683.10)
Materials and Supplies	20,021,028.27	25,061,279.42	(5,040,251.15)
Accrued Utility Revenues	(1,875,495.08)	816,939.53	(2,692,434.61)
Energy Trading	4,659,539.74	6,174,819.72	(1,515,279.98)
Prepayments	1,545,719.70	1,569,794.80	(24,075.10)
Other Current Assets	1,050,536.68	1,660,942.94	(610,406.26)
CURRENT ASSETS	**122,365,768.52**	**131,274,000.53**	**(8,908,232.01)**
REGULATORY ASSETS	**208,512,736.21**	**214,900,829.18**	**(6,388,092.97)**
TOTAL DEFERRED CHARGES	**44,323,795.36**	**78,498,798.33**	**(34,175,002.97)**
TOTAL ASSETS	**1,590,166,250.15**	**1,618,871,728.86**	**(28,705,478.71)**

Investment Accounts for Functional Property Split at November 2013 FINAL

Consol	Unit	Acct	PS Query	Production	Transmission	Distribution	General	Total
KEPCO	110	1010001	701,895,710.67	0.00	0.00	663,620,301.00	38,275,409.67	701,895,710.67
KEPCO	110	1011001	3,428,204.65	0.00	0.00	0.00	3,428,204.65	3,428,204.65
KEPCO	110	1011012	16,140.87	0.00	0.00	0.00	16,140.87	16,140.87
KEPCO	110	1050001	627,603.73	0.00	0.00	627,603.73	0.00	627,603.73
KEPCO	110	1060001	26,437,959.76	0.00	0.00	24,173,806.90	2,264,152.86	26,437,959.76
KEPCO	117	1010001	559,390,089.73	552,506,916.92	1,646,138.49	0.00	5,237,034.32	559,390,089.73
KEPCO	117	1011001	1,422,281.93	874,501.15	0.00	0.00	547,780.78	1,422,281.93
KEPCO	117	1011012	3,190.65	0.00	0.00	0.00	3,190.65	3,190.65
KEPCO	117	1050001	6,778,355.00	6,778,355.00	0.00	0.00	0.00	6,778,355.00
KEPCO	117	1060001	1,755,494.96	1,202,074.67	147.04	0.00	553,273.25	1,755,494.96
KEPCO	180	1010001	461,835,539.42	0.00	457,330,561.41	0.00	4,504,978.01	461,835,539.42
KEPCO	180	1011001	880,035.68	0.00	0.00	0.00	880,035.68	880,035.68
KEPCO	180	1011012	1,458.62	0.00	0.00	0.00	1,458.62	1,458.62
KEPCO	180	1050001	0.00	0.00	0.00	0.00	0.00	0.00
KEPCO	180	1060001	39,165,220.02	0.00	38,216,911.93	0.00	948,308.09	39,165,220.02
KEPCO Total			1,803,637,285.69	561,361,847.74	497,193,758.87	688,421,711.63	56,659,967.45	1,803,637,285.69

Preparer: Matthew Cowley, Property Accounting, Canton
Checker: Fred Francis, Property Accounting - Canton
Reviewer: Janet Swanger, Property Accounting, Canton
Sources of Information: Report GLA8300V, PowerPlant Asset - 1042 Report, Leased Asset Management System Report and PeopleSoft GL Query

Kentucky Power Corp Consol
Comparative Balance Sheet
November 30, 2013

Run Date: 12/10/2013 14:56

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V KYP_CORP_C(V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
CAPITALIZATION and LIABILITIES			
COMMON STOCK			
Authorized: 2,000,000 Shares			
Outstanding: 1,009,000 Shares			
Common Stock	50,450,000.00	50,450,000.00	0.00
Premium on Capital Stock	0.00	0.00	0.00
Paid-In-Capital	238,523,326.88	238,341,119.49	182,207.39
Retained Earnings	176,943,733.96	190,818,915.56	(13,875,181.61)
COMMON SHAREHOLDERS' EQUITY	**465,917,060.84**	**479,610,035.05**	(13,692,974.22)
PS Subject To Mandatory Redemption	0.00	0.00	0.00
PS Not Subject Mandatory Redemption	0.00	0.00	0.00
CUMULATIVE PREFERRED STOCK	**0.00**	**0.00**	**0.00**
TRUST PREFERRED SECURITIES	**0.00**	**0.00**	**0.00**
Long-Term Debt Less Amt Due 1 Yr	**549,374,781.25**	**549,221,950.00**	**152,831.25**
CAPITALIZATION	**1,015,291,842.09**	**1,028,831,985.05**	(13,540,142.97)
Obligations Under Capital Lease-NonCurrent	1,814,781.14	1,674,300.89	140,480.25
Accumulated Provision Rate Relief	0.00	1,635,430.00	(1,635,430.00)
Accumlated Provision - Miscellanous	34,580,819.24	34,033,794.12	547,025.12
Other NonCurrent Liabilities	**36,395,600.38**	**37,343,525.01**	(947,924.63)
Preferred Stock Due Within 1 Year	0.00	0.00	0.00
Long-Term Debt Due Within 1 Year	0.00	0.00	0.00
Accumulated Provision Due Within 1 Year	0.00	0.00	0.00
Short-Term Debt	0.00	0.00	0.00
Advances from Affiliates	0.00	13,358,855.63	(13,358,855.63)
A/P General	21,245,496.59	30,336,776.64	(9,091,280.05)
A/P Associated Companies	36,976,432.55	41,052,680.18	(4,076,247.64)
Customer Deposits	25,136,333.27	23,484,964.81	1,651,368.46
Taxes Accrued	9,240,911.69	6,548,714.64	2,692,197.05
Interest Accrued	11,057,801.79	7,166,695.02	3,891,106.77
Dividends Accrued	0.00	0.00	0.00
Obligation Under Capital Leases	1,095,591.08	1,403,875.95	(308,284.87)
Energy Contracts Current	2,098,566.53	3,320,068.02	(1,221,501.49)
Other Current and Accrued Liabilities	14,571,117.40	17,797,808.10	(3,226,690.70)
Current Liabilities	**121,422,250.90**	**144,470,438.99**	(23,048,188.10)
Deferred Income Taxes	**401,730,492.40**	**385,153,166.17**	**16,577,326.23**
Deferred Investment Tax Credits	**144,917.20**	**355,758.82**	(210,841.62)
Regulatory Liabilities	**8,958,919.07**	**13,831,965.72**	(4,873,046.65)
2440002 LT Unreal Losses - Non Affil	2,299,990.20	4,200,196.07	(1,900,205.87)

Kentucky Power Corp Consol
Comparative Balance Sheet
November 30, 2013

Run Date: 12/10/2013 14:56

X_OPR_COS / KYP_CORP_CI	Rpt ID: GLR2200V Layout: GLR2200V / V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
2440022	L/T Liability MTM Collateral	(80,190.00)	(582,545.00)	502,355.00
2450011	L/T Liability-Commodity Hedges	0.00	82,731.00	(82,731.00)
	Long-Term Energy Trading Contracts	2,219,800.20	3,700,382.07	(1,480,581.87)
2520000	Customer Adv for Construction	98,335.50	63,177.74	35,157.76
	Customer Advances for Construction	98,335.50	63,177.74	35,157.76
	Deferred Gains on Sale/Leaseback	0.00	0.00	0.00
	Deferred Gains on Dispostion of Utility Plant	0.00	0.00	0.00
2530000	Other Deferred Credits	0.00	0.00	0.00
2530022	Customer Advance Receipts	2,255,385.48	2,634,497.53	(379,112.05)
2530050	Deferred Rev -Pole Attachments	142,313.25	78,940.35	63,372.90
2530067	IPP - System Upgrade Credits	268,126.70	260,279.72	7,846.98
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	157,406.00	162,614.00	(5,208.00)
2530112	Other Deferred Credits-Curr	221,616.17	1,113,326.72	(891,710.55)
2530114	Federl Mitigation Deferal(NSR)	754,941.55	754,941.55	0.00
2530137	Fbr Opt Lns-Sold-Defd Rev	104,303.27	116,729.42	(12,426.15)
	Other Deferred Credits	3,904,092.42	5,121,329.29	(1,217,236.87)
	Deferred Credits	**6,222,228.12**	**8,884,889.10**	**(2,662,660.98)**
	DEFERRED CREDITS & REGULATED LIABILITIES	**417,056,556.79**	**408,225,779.81**	**8,830,776.98**
	CAPITAL & LIABILITIES	**1,590,166,250.16**	**1,618,871,728.87**	**(28,705,478.71)**

Kentucky Power Corp Consol
Comparative Balance Sheet
November 30, 2013

Run Date: 12/10/2013 14:56

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V KYP_CORP_CI V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS		Month End Balances 2013	December Balances Last Year	Variance $
Statement of Retained Earnings				
	BALANCE AT BEGINNING OF YEAR	**190,818,915.56**	**171,840,462.36**	18,978,453.21
	Net Income (Loss)	11,124,818.39	50,978,453.21	(39,853,634.81)
	Deductions:			
	Dividend Declared On Common Stock	(25,000,000.00)	-32,000,000	7,000,000.00
	Dividend Declared On Preferred Stock	0.00	0	0.00
	Adjustment in Retained Earnings	0.00	0.00	0.00
	Total Deductions	(25,000,000.00)	(32,000,000.00)	7,000,000.00
	BALANCE AT END OF PERIOD (A)	**176,943,733.96**	**190,818,915.56**	(13,875,181.61)
	(A) Represents The Following Balances At End Of Period			
215.0	Appropriated Retained Earnings	0.00	0.00	0.00
215.1	Appr Retnd Erngs - Amrt Rsv, Fed	0.00	0.00	0.00
	Total Appropriated Retained Earnings	0.00	0.00	0.00
2160000-1	Unapprp Retained Earnings Unrestr	190,818,915.56	171,840,462.36	18,978,453.21
2160002+	Unapprp Retained Earnings Restr	0.00	0.00	0.00
210.0	Gain on Reacquired Pref Stock	0.00	0.00	0.00
	Net Income Transferred	(13,875,181.61)	18,978,453.21	(32,853,634.81)
	Total Unappropriated Retained Earnings	176,943,733.96	190,818,915.56	(13,875,181.61)
216.1	Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
418.1	Equity Earnings of Subsidiary Co	0.00	0.00	0.00
	Total Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
	Total Other Retained Earnings Accounts	0.00	0.00	(0.00)
	TOTAL RETAINED EARNINGS	**176,943,733.96**	**190,818,915.56**	(13,875,181.61)

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	559,731,713.30	5,652,590.10	(4,238,718.71)	0.00	0.00	561,145,584.69
	TOTAL PRODUCTION	559,731,713.30	5,652,590.10	(4,238,718.71)	0.00	0.00	561,145,584.69
101/106	TRANSMISSION	493,489,120.26	9,131,670.84	(1,620,031.66)	0.00	0.00	501,000,759.44
101/106	DISTRIBUTION	693,312,997.44	47,192,632.26	(12,171,959.27)	0.00	0.00	728,333,670.43
	TOTAL (ACCOUNTS 101 & 106)	1,746,533,831.00	61,976,893.20	(18,030,709.64)	0.00	0.00	1,790,480,014.56
1011001/12	CAPITAL LEASES	5,182,997.28	0.00	0.00	568,315.12	0.00	5,751,312.40
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	1,751,716,828.28	61,976,893.20	(18,030,709.64)	568,315.12	0.00	1,796,231,326.96
1050001	PLANT HELD FOR FUTURE USE	7,436,550.73	0.00	0.00	0.00	(30,592.00)	7,405,958.73
107000X	CONSTRUCTION WORK IN PROGRESS:						
107000X	BEG. BAL.	44,281,291.91					
107000X	ADDITIONS		73,741,065.83				
107000X	TRANSFERS		(61,976,893.20)				
107000X	END. BAL.		11,764,172.63				56,045,464.54
	TOTAL ELECTRIC UTILITY PLANT	1,803,434,670.92	73,741,065.83	(18,030,709.64)	568,315.12	(30,592.00)	1,859,682,750.23
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	964,528.00	0.00	0.00	0.00	30,592.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,734,975.63	0.00	(2,834,483.00)	0.00	0.00	1,900,492.63
	TOTAL NONUTILITY PLANT	5,699,503.63	0.00	(2,834,483.00)	0.00	30,592.00	2,895,612.63

Prepared by: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - November, 2013

GLR7410V 12/10/13 16:19

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	273,621,070.97	18,907,604.54	(2,942,128.12)	(1,447,771.13)	0.00	288,138,776.26
1080001/11	TRANSMISSION	157,337,333.70	7,977,671.44	(1,441,165.85)	219,390.55	0.00	164,093,229.84
1080001/11	DISTRIBUTION	179,721,144.51	22,361,162.96	(8,288,013.43)	(2,131,035.67)	0.00	191,663,258.37
1080013	PRODUCTION	(3,095,458.61)	0.00	0.00	0.00	(480,293.06)	(3,575,751.67)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(17,669.03)	0.00	0.00	0.00	(8,269.83)	(25,938.86)
	RETIREMENT WORK IN PROGRESS	(6,326,680.62)	0.00	0.00	(5,351,796.39)	3,359,416.25	(8,319,060.76)
	TOTAL (108X accounts)	**601,239,740.93**	**49,246,438.94**	**(12,671,307.40)**	**(8,711,212.64)**	**2,870,853.36**	**631,974,513.19**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,461,106.71	1,163,427.13	(1,296,590.59)	0.00	0.00	10,327,943.25
1110001	TRANSMISSION	1,266,854.71	474,102.33	(178,865.81)	0.00	0.00	1,562,091.23
1110001	DISTRIBUTION	9,166,379.72	1,777,760.61	(3,883,945.84)	0.00	0.00	7,060,194.49
	TOTAL (111X accounts)	**20,894,341.14**	**3,415,290.07**	**(5,359,402.24)**	**0.00**	**0.00**	**18,950,228.97**
1011006	CAPITAL LEASES	2,104,820.44	0.00	0.00	0.00	736,119.74	2,840,940.18
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**624,238,902.51**	**52,661,729.01**	**(18,030,709.64)**	**(8,711,212.64)**	**3,606,973.10**	**653,765,682.34**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	208,286.03	6,113.91	0.00	0.00	0.00	214,399.94
1240027	Other Property - RWIP	(7,500.00)	0.00	0.00	(2,834,483.00)	2,838,583.00	(3,400.00)
1240028	Other Property - RETIRE	0.00	0.00	(2,834,483.00)	2,834,483.00	0.00	0.00
	TOTAL NONUTILITY PLANT	**200,786.03**	**6,113.91**	**(2,834,483.00)**	**0.00**	**2,838,583.00**	**210,999.94**

Prepared By: PSnVision Report GLR7410V
Reviewer: Cindy Buckbee – Prop Acctg, Canton
Sources of Info: PowerPlant Reports and PS GL

American Electric Power
1 Riverside Plaza
Columbus, OH 43215 2373
AEP.com

December 18, 2013

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed Form EIA-826, Monthly Electric Utility Sales and Revenue Report with State Distributions for the month of November 2013.

Sincerely,

Bradley M. Funk

Bradley M. Funk
Manager –Regulated Accounting

BMF
Enclosure

U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2013

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential See Section V of the General Instructions for sanctions statement Public reporting burden for this collection of information is estimated to average 1 5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D C 20585, and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D C 20503 (A person is required to respond to the collection of information only if it displays a valid OMB number) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**
Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650

Utility Name: Kentucky Power Company | **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan__ Feb__ Mar__ Apr__ May__ Jun__ Jul__ Aug__ Sep__ Oct__ Nov_X_ Dec__ , 2013

Contact Person: Ronald F Davis | **Phone number: 614-716-3525**
Email: rdavis@aep.com | **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a Revenue (Thousand Dollars)	$ 18,294	$ 11,352	$ 14,171		$ 43,817
	b Megwatthours	197,831	118,050	254,661		570,542
	c Number of consumers	139,889	30,671	1,302		171,862
	a Revenue (Thousand Dollars)					
	b Megwatthours					
	c Number of consumers					
	a Revenue (Thousand Dollars)					
	b Megwatthours					
	c Number of consumers					
	a Revenue (Thousand Dollars)					
	b Megwatthours					
	c Number of consumers					
	a Revenue (Thousand Dollars)					
	b Megwatthours					
	c Number of consumers					

Note

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

January 30, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed December 2013 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-12	Income Statement
1-3	Details of Operating Revenues
4-9	Operating Expenses – Functional Expenses
10-12	Detail Statement of Taxes
Balance Sheet:	
1	Balance Sheet – Assets & Other Debits
1-4	Balance Sheet – Liabilities & Other Credits
2-3	Deferred Credits
4	Statement of Retained Earnings
Utility Property:	
1-2	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz
Manager –Regulated Accounting

BJF

Enclosure
Cc: Lila Munsey (w/pages)

American Electric Power

INCOME STATEMENT

GLS8016
YTD Dec 2013
01/22/2014 17:19

Layout: GLS8016

09B V2099-01-01 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Corp Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Company - Distribution 110 Actual YTD Dec 2013	Kentucky Power Company - Generation 117 Actual YTD Dec 2013	Kentucky Power Company - Transmission 180 Actual YTD Dec 2013
		REVENUES					
4400001		Residential Sales-W/Space Htg	101,282,124	101,282,124	101,282,124	0	0
4400002		Residential Sales-W/O Space Ht	47,142,477	47,142,477	47,142,477	0	0
4400005		Residential Fuel Rev	67,460,107	67,460,107	67,460,107	0	0
	A	**Revenue - Residential Sales**	**215,884,709**	**215,884,709**	**215,884,709**	-	-
4420001		Commercial Sales	64,752,652	64,752,652	64,752,652	0	0
4420006		Sales to Pub Auth - Schools	11,865,009	11,865,009	11,865,009	0	0
4420007		Sales to Pub Auth - Ex Schools	12,153,558	12,153,558	12,153,558	0	0
4420013		Commercial Fuel Rev	39,540,056	39,540,056	39,540,056	0	0
	A	**Revenue - Commercial Sales**	**128,311,276**	**128,311,276**	**128,311,276**	-	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-	-
4420002		Industrial Sales (Excl Mines)	54,880,071	54,880,071	54,880,071	0	0
4420004		Ind Sales-NonAffil(Incl Mines)	27,940,176	27,940,176	27,940,176	0	0
4420016		Industrial Fuel Rev	83,624,704	83,624,704	83,624,704	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**166,444,951**	**166,444,951**	**166,444,951**	-	-
		Revenue - Industrial Sales	**166,444,951**	**166,444,951**	**166,444,951**	-	-
	A	**Revenue - Gas Products Sales**	-	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-	-
4440000		Public Street/Highway Lighting	1,255,871	1,255,871	1,255,871	0	0
4440002		Public St & Hwy Light Fuel Rev	304,475	304,475	304,475	0	0
	A	**Revenue - Other Retail Sales**	**1,560,346**	**1,560,346**	**1,560,346**	-	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-	-
		Revenue - Retail Sales	**512,201,281**	**512,201,281**	**512,201,281**	-	-
4560043		Oth Elec Rv-Trn-Aff-Trnf Prnce	0	0	0	0	33,138,718
4561033		PJM NITS Revenue - Affiliated	36,560,877	36,560,877	0	0	36,560,877
4561034		PJM TO Adm. Serv Rev - Aff	371,957	371,957	0	0	513,392
4561035		PJM Affiliated Trans NITS Cost	(35,845,588)	(35,845,588)	0	(35,845,588)	0
4561036		PJM Affiliated Trans TO Cost	(363,306)	(363,306)	0	(504,742)	0
4561059		Affil PJM Trans Enhancmnt Rev	285,820	285,820	0	0	285,820
4561060		Affil PJM Trans Enhancmnt Cost	(280,267)	(280,267)	0	(280,267)	0
4561062		PROVISION PJM NITS Affil- Cost	410,634	410,634	0	410,634	0
4561063		PROVISION PJM NITS Affiliated	(278,482)	(278,482)	0	0	(278,482)
	B	**Revenue - Transmission-Affiliated**	**861,645**	**861,645**	-	**(36,219,963)**	**70,220,326**
4470150		Transm. Rev -Dedic. Whsl/Muni	45,085	45,085	0	(640,793)	685,878
4470206		PJM Trans loss credits-OSS	976,320	976,320	0	976,320	0
4470207		PJM transm loss charges - LSE	(8,049,230)	(8,049,230)	0	(8,049,230)	0
4470208		PJM Transm loss credits-LSE	1,725,348	1,725,348	0	1,725,348	0
4470209		PJM transm loss charges-OSS	(4,563,871)	(4,563,871)	0	(4,563,871)	0
4561002		RTO Formation Cost Recovery	6,291	6,291	0	(140,097)	146,388
4561003		PJM Expansion Cost Recov	84,377	84,377	0	(84,654)	169,031
4561005		PJM Point to Point Trans Svc	621,335	621,335	0	621,335	0
4561006		PJM Trans Owner Admin Rev	223,781	223,781	0	0	223,781
4561007		PJM Network Integ Trans Svc	13,097,720	13,097,720	0	0	13,097,720
4561019		Oth Elec Rev Trans Non Affil	57,068	57,068	0	0	57,068
4561028		PJM Pow Fac Crs Rev Whsl Cu-NA	7,199	7,199	0	0	7,199
4561029		PJM NITS Revenue Whsl Cus-NAff	2,353,705	2,353,705	0	0	2,353,705
4561030		PJM TO Serv Rev Whls Cus-NAff	36,642	36,642	0	0	36,642
4561058		NonAffil PJM Trans Enhncmt Rev	253,346	253,346	0	0	253,346
4561061		NAff PJM RTEP Rev for Whsl-FR	18,420	18,420	0	0	18,420
4561064		PROVISION PJM NITS WhslCus-NAf	(18,719)	(18,719)	0	0	(18,719)
4561065		PROVISION PJM NITS	(78,225)	(78,225)	0	0	(78,225)
	A	**Revenue - Transmission-NonAffiliated**	**6,796,589**	**6,796,589**	-	**(10,155,642)**	**16,952,232**

American Electric Power

INCOME STATEMENT

GLS8016
YTD Dec 2013
01/22/2014 17:19

09B V2099-01-01 Layout: GLS8016 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

		Kentucky Power Int Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Corp Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Company - Distribution 110 Actual YTD Dec 2013	Kentucky Power Company - Generation 117 Actual YTD Dec 2013	Kentucky Power Company - Transmission 180 Actual YTD Dec 2013
	Revenue - Transmission	**7,658,234**	**7,658,234**	**-**	**(46,375,605)**	**87,172,557**
4470001	Sales for Resale - Assoc Cos	9,622	9,622	0	9,622	0
4470035	Sls for Rsl - Fuel Rev - Assoc	109,116	109,116	0	109,116	0
4470127	Sales for Res-Affil Pool Cap	10,478,265	10,478,265	0	0	0
4470128	Sales for Res-Aff Pool Energy	69,431,296	69,431,296	0	43,496,206	0
B	**Revenue - Resale-Affiliated**	**80,028,299**	**80,028,299**	**-**	**43,614,944**	**-**
4210043	Realiz Sharing West Coast Pwr	15	15	0	15	0
4470002	Sales for Resale - NonAssoc	4,237,097	4,237,097	0	4,237,097	0
4470006	Sales for Resale-Bookout Sales	14,893,779	14,893,779	0	14,893,779	0
4470010	Sales for Resale-Bookout Purch	(10,466,461)	(10,466,461)	0	(10,466,461)	0
4470027	Whsal/Muni/Pb Ath Fuel Rev	2,770,589	2,770,589	0	2,770,589	0
4470028	Sale/Resale - NA - Fuel Rev	110,599,630	110,599,630	0	3,826,407	0
4470033	Whsal/Muni/Pub Auth Base Rev	1,834,151	1,834,151	0	1,834,151	0
4470066	PWR Trding Trans Exp-NonAssoc	(2,501)	(2,501)	0	(2,501)	0
4470081	Financial Spark Gas - Realized	429,329	429,329	0	429,329	0
4470082	Financial Electric Realized	(3,445,317)	(3,445,317)	0	(3,445,317)	0
4470089	PJM Energy Sales Margin	9,235,926	9,235,926	0	9,235,926	0
4470093	PJM Implicit Congestion-LSE	(4,421,545)	(4,421,545)	0	(4,421,545)	0
4470098	PJM Oper Reserve Rev-OSS	1,483,423	1,483,423	0	1,483,423	0
4470099	Capacity Cr Net Sales	4,101,282	4,101,282	0	455,842	0
4470100	PJM FTR Revenue-OSS	359,156	359,156	0	359,156	0
4470101	PJM FTR Revenue-LSE	3,143,193	3,143,193	0	3,143,193	0
4470103	PJM Energy Sales Cost	59,439,740	59,439,740	0	59,439,740	0
4470106	PJM Pt2Pt Trans Purch-NonAff	(1,612)	(1,612)	0	(1,612)	0
4470107	PJM NITS Purch-NonAff	(19,677)	(19,677)	0	(19,677)	0
4470109	PJM FTR Revenue-Spec	8,710	8,710	0	8,710	0
4470110	PJM TO Admin Exp -NonAff	(1,414)	(1,414)	0	(1,414)	0
4470112	Non-Trading Bookout Sales-OSS	(2,027)	(2,027)	0	(2,027)	0
4470115	PJM Meter Corrections-OSS	33,107	33,107	0	33,107	0
4470116	PJM Meter Corrections-LSE	85,847	85,847	0	85,847	0
4470124	PJM Incremental Spot-OSS	(0)	(0)	0	(0)	0
4470126	PJM Incremental Imp Cong-OSS	(3,465,776)	(3,465,776)	0	(3,465,776)	0
4470131	Non-Trading Bookout Purch-OSS	180	180	0	180	0
4470143	Financial Hedge Realized	148,039	148,039	0	148,039	0
4470144	Realiz Sharing - 06 SIA	1,592	1,592	0	1,592	0
4470155	OSS Physical Margin Reclass	(1,292,057)	(1,292,057)	0	(1,292,057)	0
4470156	OSS Optim Margin Reclass	1,292,057	1,292,057	0	1,292,057	0
4470168	Interest Rate Swaps-Power	(32,459)	(32,459)	0	(32,459)	0
4470170	Non-ECR Auction Sales-OSS	5,081,836	5,081,836	0	5,081,836	0
4470174	PJM Whlse FTR Rev - OSS	104,886	104,886	0	104,886	0
4470175	OSS Sharing Reclass - Retail	(771,004)	(771,004)	0	(771,004)	0
4470176	OSS Sharing Reclass-Reduction	771,004	771,004	0	771,004	0
4470180	Trading intra-book Reclass	(22,454)	(22,454)	0	(22,454)	0
4470181	Auction intra-book Reclass	22,454	22,454	0	22,454	0
4470202	PJM OpRes-LSE-Credit	4,332,903	4,332,903	0	4,332,903	0
4470203	PJM OpRes-LSE-Charge	(2,112,783)	(2,112,783)	0	(2,101,654)	(11,129)
4470214	PJM 30m Suppl Reserve CR OSS	247,980	247,980	0	247,980	0
4470220	PJM Regulation - OSS	12,396	12,396	0	12,396	0
4470221	PJM Spinning Reserve - OSS	59,388	59,388	0	59,388	0
4470222	PJM Reasctive - OSS	416,224	416,224	0	416,224	0
4560049	Merch Generation Finan -Realzd	(2)	(2)	0	(2)	0
4560050	Oth Elec Rev-Coal Trd Rlzd G-L	41,229	41,229	0	41,229	0
5550080	PJM Hourly Net Purch -FERC	(9,463,790)	(9,463,790)	0	(9,463,790)	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Dec 2013
01/22/2014 17:19

Layout: GLS8016

09B V2099-01-01		Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Corp Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Company - Distribution 110 Actual YTD Dec 2013	Kentucky Power Company - Generation 117 Actual YTD Dec 2013	Kentucky Power Company - Transmission 180 Actual YTD Dec 2013
5550094		Purchased Power - Fuel	(520,332)	(520,332)	0	(520,332)	0
	A	**Revenue - Resale-NonAffiliated**	**189,145,929**	**189,145,929**	-	**78,738,396**	**(11,129)**
	A	**Revenue - Resale-Realized**	-	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-	-
		Revenue - Sales for Resale	**269,174,228**	**269,174,228**	-	**122,353,340**	**(11,129)**
4470074		Sale for Resale-Aff-Trnf Price	0	0	0	370,035,081	0
4540001		Rent From Elect Property - Af	262,212	262,212	778,013	0	0
	B	**Revenue - Other Ele-Affiliated**	**262,212**	**262,212**	**778,013**	**370,035,081**	-
4500000		Forfeited Discounts	3,340,356	3,340,356	3,340,356	0	0
4510001		Misc Service Rev - Nonaffil	380,114	380,114	366,558	0	13,556
4540002		Rent From Elect Property-NAC	100,292	100,292	2,450	84,042	13,800
4540005		Rent from Elec Prop-Pole Attch	5,931,881	5,931,881	5,931,881	0	0
4560007		Oth Elect Rev - DSM Program	3,323,488	3,323,488	3,323,488	0	0
		Revenue - Other Ele-NonAffiliated	**13,076,130**	**13,076,130**	**12,964,732**	**84,042**	**27,356**
		Revenue - Gas	-	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	164	164	0	164	0
4118003		Comp. Allow. Gains-Seas NOx	26,316	26,316	0	26,316	0
4118004		Comp. Allow. Gains-Ann NOx	114,248	114,248	0	114,248	0
		Gain/(Loss) on Allowances	**140,729**	**140,729**	-	**140,729**	-
	A	**Revenue - Other Ele-NonAffiliated**	**13,216,859**	**13,216,859**	**12,964,732**	**224,771**	**27,356**
		Revenue - Other Opr Electric	**13,479,071**	**13,479,071**	**13,742,746**	**370,259,851**	**27,356**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-	-
4180001		Non-Operatng Rental Income	35,600	35,600	34,400	1,200	0
4180003		Non-Opratng Rntal Inc-Maint	(992)	(992)	0	(992)	0
4180005		Non-Opratng Rntal Inc-Depr	(6,670)	(6,670)	0	0	(6,670)
	D	**Non-Operating Rental Income - NonAffiliated**	**27,938**	**27,938**	**34,400**	**208**	**(6,670)**
		Non-Operating Rental Income	**27,938**	**27,938**	**34,400**	**208**	**(6,670)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	20,211	20,211	1,048	18,555	609
4210005		Misc Non-Op Inc-NonAsc-Timber	36,616	36,616	0	36,616	0
4210007		Misc Non-Op Inc - NonAsc - Oth	10,950	10,950	10,918	23	10
	D	**Non-Operating Misc Income - NonAffiliated**	**67,777**	**67,777**	**11,965**	**55,193**	**619**
		Non-Operating Misc Income	**67,777**	**67,777**	**11,965**	**55,193**	**619**
4540004		Rent From Elect Prop-ABD-Nonaf	109,221	109,221	109,221	0	0
4560015		Other Electric Revenues - ABD	479,654	479,654	299,497	0	180,157
	D	**Associated Business Development Income**	**588,876**	**588,876**	**408,719**	-	**180,157**
		Revenue - Other Opr - Other	**684,591**	**684,591**	**455,084**	**55,401**	**174,106**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***684,591***	***684,591***	***455,084***	***55,401***	***174,106***
		Revenue - Other Operating	**14,163,662**	**14,163,662**	**14,197,830**	**370,315,253**	**201,462**
4491003		Prov Rate Refund - Retail	478,327	478,327	478,327	0	0
	A	**Provision for Rate Refund - NonAffiliated**	**478,327**	**478,327**	**478,327**	-	-
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-	-
		Provision for Rate Refund	**478,327**	**478,327**	**478,327**	-	-
4210031		Pwr Sales Outside Svc Terrtry	1,267	1,267	0	1,267	0
4210032		Pwr Purch Outside Svc Terrtry	(539)	(539)	0	(539)	0
	A	**Revenue - Power Sales**	**728**	**728**	-	**728**	-
		TOTAL OPERATING REVENUES	**803,676,461**	**803,676,461**	**526,877,438**	**446,293,715**	**87,362,890**

American Electric Power

INCOME STATEMENT

GLS8016
YTD Dec 2013
01/22/2014 17:19

Layout: GLS8016

098 V2099-01-01 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

		Kentucky Power Int Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Corp Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Company - Distribution 110 Actual YTD Dec 2013	Kentucky Power Company - Generation 117 Actual YTD Dec 2013	Kentucky Power Company - Transmission 180 Actual YTD Dec 2013
=(A)	*Memo: G/T/D Revenue*	*721,839,713*	*721,839,713*	*525,644,340*	*68,808,252*	*16,968,459*
=(B)	*Memo: Other Affiliated Revenue*	*81,152,156*	*81,152,156*	*778,013*	*377,430,062*	*70,220,326*
=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth Non*	*684,591*	*684,591*	*455,084*	*55,401*	*174,106*
	Memo: Total Operating Revenues	*803,676,461*	*803,676,461*	*526,877,438*	*446,293,715*	*87,362,890*
=(E)=(B)+(C)	*Memo: Affiliated Revenue*	***81,152,156***	***81,152,156***	***778,013***	***377,430,062***	***70,220,326***
=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	***722,524,304***	***722,524,304***	***526,099,424***	***68,863,653***	***17,142,565***
	Memo: Total Operating Revenues	***803,676,461***	***803,676,461***	***526,877,438***	***446,293,715***	***87,362,890***
	FUEL EXPENSES					
5010000	Fuel	741,231	741,231	0	359,525	0
5010001	Fuel Consumed	180,375,167	180,375,167	0	92,807,820	0
5010003	Fuel - Procure Unload & Handle	5,395,599	5,395,599	0	2,792,960	0
5010012	Ash Sales Proceeds	(32,273)	(32,273)	0	(9,325)	0
5010013	Fuel Survey Activity	(1,023,454)	(1,023,454)	0	(1)	0
5010019	Fuel Oil Consumed	5,867,763	5,867,763	0	2,611,727	0
5010027	Gypsum handling/disposal costs	673,094	673,094	0	0	0
5010028	Gypsum Sales Proceeds	(440,753)	(440,753)	0	0	0
	Fuel Expense Total	**191,556,374**	**191,556,374**	-	**98,562,706**	-
5010005	Fuel - Deferred	(5,077,685)	(5,077,685)	0	(5,077,685)	0
	Deferred Fuel Expense	**(5,077,685)**	**(5,077,685)**	-	**(5,077,685)**	-
	Over Under Fuel Expense					
	Fuel for Electric Generation	**186,478,689**	**186,478,689**	-	**93,485,021**	-
5010029	Gypsum handling/displ-Affiliat	274,411	274,411	0	0	0
	Fuel from Affiliates for Electric Generation	**274,411**	**274,411**	-	-	-
5090000	Allow Consum Title IV SO2	5,917,402	5,917,402	0	5,788,988	0
5090001	Allowance Consumption - NOx	7,637	7,637	0	0	0
5090002	Allowance Expenses	1	1	0	1	0
5090005	An. NOx Cons. Exp	59,191	59,191	0	14,461	0
	Allowances - Consumption	**5,984,231**	**5,984,231**	-	**5,803,450**	-
5020002	Urea Expense	3,831,808	3,831,808	0	2,082,479	0
5020003	Trona Expense	550,513	550,513	0	0	0
5020004	Limestone Expense	3,006,454	3,006,454	0	0	0
5020005	Polymer expense	2,154	2,154	0	0	0
5020007	Lime Hydrate Expense	11,264	11,264	0	0	0
5020027	Capacity Cost Consumable OvUnd	(5,080,300)	(5,080,300)	0	0	0
	Emissions Control - Chemicals	**2,321,893**	**2,321,893**	-	**2,082,479**	-
	Total Fuel for Electric Generation	**195,059,223**	**195,059,223**	-	**101,370,950**	-
	Memo: NonAff Fuel/Allow/Emissions	***194,784,813***	***194,784,813***	-	***101,370,950***	-
5550004	Purchased Power-Pool Capacity	26,276,737	26,276,737	0	27,967,887	0
5550005	Purchased Power - Pool Energy	71,516,038	71,516,038	0	76,233,329	0
5550027	Purch Pwr-Non-Fuel Portion-Aff	46,637,770	46,637,770	0	46,637,770	0
5550029	Purch Power-Assoc-Trnsfr Price	0	0	370,035,081	0	0
5550046	Purch Power-Fuel Portion-Affil	61,156,726	61,156,726	0	61,156,726	0
5550101	Purch Power-Pool Non-Fuel -Aff	10,786,601	10,786,601	0	10,786,601	0
5550102	Pur Power-Pool NonFuel-OSS-Aff	52,713,882	52,713,882	0	52,713,882	0
	Purchased Electricity from AEP - Affiliates	**269,087,753**	**269,087,753**	**370,035,081**	**275,496,195**	-
5550001	Purch Pwr-NonTrading-Nonassoc	1,113,840	1,113,840	0	1,113,840	0
5550032	Gas-Conversion-Mone Plant	373,305	373,305	0	373,305	0
5550039	PJM Inadvertent Mtr Res-OSS	(18,238)	(18,238)	0	(18,238)	0
5550040	PJM Inadvertent Mtr Res-LSE	(37,266)	(37,266)	0	(37,266)	0
5550041	PJM Ancillary Serv.-Sync	2,495	2,495	0	2,495	0

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5550074	PJM Reactive-Charge	6,719	6,719	0	6,719	0
5550075	PJM Reactive-Credit	112,176	112,176	0	112,176	0
5550076	PJM Black Start-Charge	3,983,892	3,983,892	0	3,983,892	0
5550077	PJM Black Start-Credit	(11,744)	(11,744)	0	(11,744)	0
5550078	PJM Regulation-Charge	1,311,083	1,311,083	0	1,311,083	0
5550079	PJM Regulation-Credit	(343,820)	(343,820)	0	(343,820)	0
5550083	PJM Spinning Reserve-Charge	76,575	76,575	0	76,575	0
5550084	PJM Spinning Reserve-Credit	(30,396)	(30,396)	0	(30,396)	0
5550090	PJM 30m Suppl Rserv Charge LSE	276,238	276,238	0	276,238	0
5550099	PJM Purchases-non-ECR-Auction	3,885,252	3,885,252	0	3,885,252	0
5550100	Capacity Purchases-Auction	119,060	119,060	0	119,060	0
5550107	Capacity purchases - Trading	183,321	183,321	0	183,321	0
5550117	Capacity Cst OvUnd Purch Power	(5,328,670)	(5,328,670)	0	0	0
	Purchased Electricity for Resale - NonAffiliated	**5,673,822**	**5,673,822**	**-**	**11,002,493**	**-**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**	**-**
	Total Purchased Power	**274,761,576**	**274,761,576**	**370,035,081**	**286,498,688**	**-**
	GROSS MARGIN	**333,855,661**	**333,855,661**	**156,842,357**	**58,424,078**	**87,362,890**
	OPERATING EXPENSES					
5000000	Oper Supervision & Engineering	3,554,298	3,554,298	0	1,769,648	0
5000001	Oper Super & Eng-RATA-Affil	61,000	61,000	0	28,000	0
5020000	Steam Expenses	2,768,263	2,768,263	0	858,939	0
5020025	Steam Exp Environmental	2,161	2,161	0	(7)	0
5020026	Capacity Cost Ov Und O&M	(925,744)	(925,744)	0	0	0
5050000	Electric Expenses	405,673	405,673	0	399,129	0
5060000	Misc Steam Power Expenses	7,831,362	7,831,362	0	4,300,342	0
5060001	Dresden Misc Steam Pwer Exp	8	8	0	4	0
5060002	Misc Steam Power Exp-Assoc	89,133	89,133	0	23,197	0
5060003	Removal Cost Expense - Steam	2,337,874	2,337,874	0	0	0
5060004	NSR Settlement Expense	(27,037)	(27,037)	0	(19,087)	0
5060025	Misc Stm Pwr Exp Environmental	618	618	0	16	0
5060026	Capacity Cost Ov-Und Rec Exp	(3,590,079)	(3,590,079)	0	0	0
5070000	Rents	1,109	1,109	0	900	0
	Steam Generation Op Exp	**12,508,640**	**12,508,640**	**-**	**7,361,081**	**-**
5170000	Oper Supervision & Engineering	1,074	1,074	0	0	1,074
	Nuclear Generation Op Exp	**1,074**	**1,074**	**-**	**-**	**1,074**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	299,908	299,908	0	138,024	0
5570000	Other Expenses	1,854,031	1,854,031	0	1,319,263	0
5570007	Other Pwr Exp - Wholesale RECs	18,433	18,433	18,433	0	0
5757000	PJM Admin-MAM&SC- OSS	328,130	328,130	0	328,130	0
5757001	PJM Admin-MAM&SC- internal	657,519	657,519	0	657,519	0
	Other Generation Op Exp	**3,158,020**	**3,158,020**	**18,433**	**2,442,936**	**-**
5600000	Oper Supervision & Engineering	888,954	888,954	4,020	2,160	882,775
5611000	Load Dispatch - Reliability	9,421	9,421	0	0	9,421
5612000	Load Dispatch-Mntr&Op TransSys	821,922	821,922	346	191	821,386
5614000	PJM Admin-SSC&DS-OSS	315,659	315,659	0	315,659	0
5614001	PJM Admin-SSC&DS-Internal	649,581	649,581	0	649,581	0
5614007	RTO Admin Default LSE	(9,568)	(9,568)	0	(2,780)	(6,788)
5615000	Reliability Plng&Stds Develop	145,934	145,934	9,072	4,056	132,806
5616000	PJM Admin-RP&SDS-OSS	69,137	69,137	0	69,137	0
5616001	PJM Admin-RP&SDS- Internal	155,936	155,936	0	155,936	0

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5620001	Station Expenses - Nonassoc	313,852	313,852	3,708	0	310,144
5630000	Overhead Line Expenses	119,542	119,542	0	0	119,542
5650002	Transmssn Elec by Others-NAC	185,837	185,837	0	114,512	71,325
5650007	Tran Elec by Oth-Aff-Trn Pnce	0	0	33,138,718	0	0
5650012	PJM Trans Enhancement Charge	3,487,776	3,487,776	0	3,487,776	0
5650015	PJM TO Serv Exp - Aff	13,493	13,493	0	13,493	0
5650016	PJM NITS Expense - Affiliated	2,651,959	2,651,959	0	2,651,959	0
5650019	Affil PJM Trans Enhncement Exp	130,031	130,031	0	130,031	0
5650020	PROVISION PJM NITS Affl Expens	233,799	233,799	0	233,799	0
5660000	Misc Transmission Expenses	1,115,512	1,115,512	13,234	7,763	1,094,516
5670001	Rents - Nonassociated	11,069	11,069	0	0	11,069
5670002	Rents - Associated	0	0	0	0	515,801
5757002	SPP Admin-MAM&SC	0	0	0	0	0
	Transmission Op Exp	**11,309,849**	**11,309,849**	**33,169,098**	**7,833,274**	**3,961,997**
5800000	Oper Supervision & Engineering	707,004	707,004	698,770	1,055	7,180
5810000	Load Dispatching	3,131	3,131	3,129	0	2
5820000	Station Expenses	163,715	163,715	163,448	0	267
5830000	Overhead Line Expenses	577,534	577,534	577,479	55	(0)
5840000	Underground Line Expenses	131,141	131,141	131,141	0	0
5850000	Street Lighting & Signal Sys E	118,881	118,881	118,881	0	0
5860000	Meter Expenses	686,805	686,805	686,529	12	263
5870000	Customer Installations Exp	161,182	161,182	161,182	0	0
5880000	Miscellaneous Distribution Exp	4,021,874	4,021,874	3,972,403	11,408	38,063
5890001	Rents - Nonassociated	1,530,362	1,530,362	1,530,362	0	0
5890002	Rents - Associated	65,626	65,626	65,626	0	0
	Distribution Op Exp	**8,167,255**	**8,167,255**	**8,108,950**	**12,530**	**45,775**
9010000	Supervision - Customer Accts	285,400	285,400	285,269	71	61
9020000	Meter Reading Expenses	(771)	(771)	(1,110)	174	165
9020002	Meter Reading - Regular	394,144	394,144	394,144	0	0
9020003	Meter Reading - Large Power	43,045	43,045	43,045	0	0
9020004	Read-In & Read-Out Meters	47,273	47,273	47,273	0	0
9030000	Cust Records & Collection Exp	340,777	340,777	334,176	123	6,477
9030001	Customer Orders & Inquiries	2,099,135	2,099,135	2,099,123	(4)	16
9030002	Manual Billing	35,058	35,058	33,972	21	1,066
9030003	Postage - Customer Bills	857,985	857,985	857,985	0	0
9030004	Cashiering	125,433	125,433	125,274	77	83
9030005	Collection Agents Fees & Exp	39,038	39,038	39,038	0	0
9030006	Credit & Oth Collection Activi	760,348	760,348	760,264	44	41
9030007	Collectors	577,679	577,679	577,679	0	0
9030009	Data Processing	163,058	163,058	163,058	0	0
9040007	Uncoll Accts - Misc Receivable	(54,515)	(54,515)	(54,690)	175	0
9050000	Misc Customer Accounts Exp	20,469	20,469	20,445	13	11
9070000	Supervision - Customer Service	147,639	147,639	147,618	11	10
9070001	Supervision - DSM	9	9	2	4	3
9080000	Customer Assistance Expenses	483,992	483,992	483,984	5	4
9080001	DSM-Customer Advisory Grp	609	609	609	0	0
9080004	Cust Assistnce Exp - DSM - Ind	(1)	(1)	(1)	(0)	(0)
9080009	Cust Assistance Expense - DSM	2,882,805	2,882,805	2,881,893	415	498
9090000	Information & Instruct Advrtis	140,472	140,472	62,750	38,787	38,934
9100000	Misc Cust Svc&Informational Ex	35,493	35,493	18,467	8,824	8,202
	Customer Service and Information Op Exp	**9,424,573**	**9,424,573**	**9,320,265**	**48,739**	**55,570**
9120000	Demonstrating & Selling Exp	30,362	30,362	30,362	0	0
9120001	Demo & Selling Exp - Res	2	2	0	2	0

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9120003	Demo & Selling Exp - Area Dev	349	349	349	0	0
	Sales Expenses	**30,713**	**30,713**	**30,712**	**2**	**-**
	Memo: Insurance (9240 9250)	**2,987,365**	**2,987,365**	**1,380,368**	**523,879**	**286,719**
9200000	Administrative & Gen Salaries	11,681,530	11,681,530	4,509,167	3,306,516	1,592,091
9210001	Off Supl & Exp - Nonassociated	1,277,778	1,277,778	499,409	400,415	205,794
9210003	Office Supplies & Exp - Trnsf	83	83	26	16	15
9220000	Administrative Exp Trnsf - Cr	(626,603)	(626,603)	(626,603)	0	(0)
9220001	Admin Exp Trnsf to Cnstrction	(551,850)	(551,850)	(551,850)	0	0
9220004	Admin Exp Trnsf to ABD	(8,390)	(8,390)	(6,729)	0	(1,662)
9230001	Outside Svcs Empl - Nonassoc	2,979,264	2,979,264	947,766	956,643	380,357
9230003	AEPSC Billed to Client Co	(805,087)	(805,087)	(225,201)	(179,914)	(214,885)
9240000	Property Insurance	861,696	861,696	168,025	193,066	188,761
9250000	Injuries and Damages	1,291,514	1,291,514	855,188	192,093	48,500
9250001	Safety Dinners and Awards	1,853	1,853	1,191	459	203
9250002	Emp Accdent Prvntion-Adm Exp	14,288	14,288	11,048	1,029	1,132
9250004	Injuries to Employees	11,666	11,666	0	1,529	(4)
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	939,562	939,562	681,781	88,190	86,112
9250007	Prsnal Injrës&Prop Dmage-Pub	310,661	310,661	4,266	77,744	2
9250010	Frg Ben Loading - Workers Comp	(443,875)	(443,875)	(341,130)	(30,231)	(37,988)
9260000	Employee Pensions & Benefits	18,665	18,665	14,635	108	49
9260001	Edit & Print Empl Pub-Salaries	12,562	12,562	6,041	2,278	1,901
9260002	Pension & Group Ins Admin	30,336	30,336	13,515	6,404	1,716
9260003	Pension Plan	4,842,842	4,842,842	2,532,324	1,212,219	313,374
9260004	Group Life Insurance Premiums	146,336	146,336	74,487	36,117	13,003
9260005	Group Medical Ins Premiums	4,567,754	4,567,754	2,361,542	1,028,125	416,721
9260006	Physical Examinations	28	28	0	0	28
9260007	Group L-T Disability Ins Prem	13,896	13,896	7,407	2,834	1,257
9260009	Group Dental Insurance Prem	281,857	281,857	149,636	62,038	22,736
9260010	Training Administration Exp	3,481	3,481	1,918	370	872
9260012	Employee Activities	6,499	6,499	4,955	673	205
9260014	Educational Assistance Pmts	6,399	6,399	4,761	0	0
9260021	Postretirement Benefits - OPEB	(1,828,081)	(1,828,081)	(890,933)	(469,322)	(140,039)
9260027	Savings Plan Contributions	1,733,835	1,733,835	883,440	379,364	141,068
9260036	Deferred Compensation	14,289	14,289	14,242	0	0
9260037	Supplemental Pension	10,663	10,663	3,895	0	0
9260040	SFAS 112 Postemployment Benef	(126,445)	(126,445)	0	0	0
9260050	Frg Ben Loading - Pension	(1,803,596)	(1,803,596)	(1,237,868)	(260,616)	(171,490)
9260051	Frg Ben Loading - Grp Ins	(2,127,219)	(2,127,219)	(1,393,857)	(274,873)	(274,873)
9260052	Frg Ben Loading - Savings	(634,139)	(634,139)	(408,551)	(88,035)	(77,016)
9260053	Frg Ben Loading - OPEB	107,396	107,396	42,207	28,746	25,261
9260055	IntercoFringeOffset- Don't Use	(947,909)	(947,909)	(556,560)	(82,760)	(293,068)
9260057	Postret Ben Medicare Subsidy	652,057	652,057	289,959	170,118	32,992
9260058	Frg Ben Loading - Accrual	(4,279)	(4,279)	(8,914)	1,564	2,007
9260060	Amort-Post Retirement Benefit	216,620	216,620	129,581	71,207	15,832
9270000	Franchise Requirements	142,255	142,255	142,255	0	0
9280000	Regulatory Commission Exp	62,961	62,961	28,700	15,362	18,346
9280001	Regulatory Commission Exp-Adm	(0)	(0)	(0)	(0)	(0)
9280002	Regulatory Commission Exp-Case	226,893	226,893	69,712	89,400	45,057
9301000	General Advertising Expenses	10,894	10,894	2,304	1,361	1,430
9301001	Newspaper Advertising Space	21,635	21,635	9,940	6,006	5,689
9301002	Radio Station Advertising Time	72	72	22	14	14
9301003	TV Station Advertising Time	2,600	2,600	1,164	711	725
9301010	Publicity	3,413	3,413	1,332	814	766

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9301012	Public Opinion Surveys	4,388	4,388	4,379	0	8
9301014	Video Communications	10	10	3	2	2
9301015	Other Corporate Comm Exp	25,883	25,883	17,019	4,362	4,214
9302000	Misc General Expenses	195,621	195,621	65,743	50,750	9,671
9302003	Corporate & Fiscal Expenses	32,669	32,669	14,865	2,737	2,833
9302004	Research, Develop&Demonstr Exp	3,453	3,453	3,453	0	0
9302458	AEPSC Non Affliated expenses	13	13	0	7	0
9310000	Rents	1,363	1,363	0	0	1,363
9310001	Rents - Real Property	94,032	94,032	92,176	0	0
9310002	Rents - Personal Property	127,930	127,930	71,472	33,710	9,813
	Administration & General	**23,084,020**	**23,084,020**	**8,488,754**	**7,039,351**	**2,381,096**
4111005	Accretion Expense	423,043	423,043	0	0	0
	Accretion	**423,043**	**423,043**	-	-	-
4116000	Gain From Disposition of Plant	(3,536)	(3,536)	(3,536)	0	0
	Loss/(Gain) on Utility Plant	**(3,536)**	**(3,536)**	**(3,536)**	-	-
9302006	Assoc Bus Dev - Materials Sold	41,678	41,678	41,678	0	0
9302007	Assoc Business Development Exp	239,471	239,471	108,506	17	130,948
	Associated Business Development Expenses	**281,150**	**281,150**	**150,184**	**17**	**130,948**
4211000	Gain on Dspsition of Property	(1,768,048)	(1,768,048)	0	(1,768,048)	0
	Gain on Disposition of Property	**(1,768,048)**	**(1,768,048)**	-	**(1,768,048)**	-
4212000	Loss on Dspsition of Property	7,425	7,425	0	0	7,425
	Loss on Disposition of Property	**7,425**	**7,425**	-	-	**7,425**
	Loss(Gain) of Sale of Property	**(1,760,623)**	**(1,760,623)**	-	**(1,768,048)**	**7,425**
4265009	Factored Cust A/R Exp - Affil	829,600	829,600	829,600	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,175,163	1,175,163	1,175,163	0	0
	Opr Exp and Factored A/R	**2,004,762**	**2,004,762**	**2,004,762**	-	-
	Water Heaters	-	-	-	-	-
4265004	Social & Service Club Dues	52,608	52,608	21,731	18,076	12,802
	Expense of Non-Utility Operation	**52,608**	**52,608**	**21,731**	**18,076**	**12,802**
4210009	Misc Non-Op Exp - NonAssoc	12,508	12,508	3,276	7,217	2,014
	Misc NonOp Expenses - NonAssoc	**12,508**	**12,508**	**3,276**	**7,217**	**2,014**
4261000	Donations	372,322	372,322	281,770	46,342	44,210
	Donation Contributions	**372,322**	**372,322**	**281,770**	**46,342**	**44,210**
4263001	Penalties	3,876	3,876	1,242	14	2,620
	Provision for Penalties	**3,876**	**3,876**	**1,242**	**14**	**2,620**
4264000	Civic & Political Activities	247,726	247,726	113,599	64,084	70,043
	Civic & Political Activities	**247,726**	**247,726**	**113,599**	**64,084**	**70,043**
4265002	Other Deductions - Nonassoc	34,027,912	34,027,912	6,944	34,016,650	4,319
4265033	Ohio Merger - Transition Costs	23,459	23,459	0	23,459	0
	Other Deductions	**34,051,371**	**34,051,371**	**6,944**	**34,040,109**	**4,319**
	Shutdown Coal Company Expenses	-	-	-	-	-
	All Other Operational Expenses	**36,745,173**	**36,745,173**	**2,433,325**	**34,175,840**	**136,008**
	Operational Expenses	**103,369,351**	**103,369,351**	**61,716,185**	**57,145,721**	**6,719,892**
5100000	Maint Supv & Engineering	3,766,711	3,766,711	0	1,821,917	0
5110000	Maintenance of Structures	1,372,910	1,372,910	0	872,829	0
5120000	Maintenance of Boiler Plant	18,608,137	18,608,137	0	6,565,943	0
5120025	Maint of Blr Plt Environmental	21	21	0	0	0
5130000	Maintenance of Electric Plant	6,142,120	6,142,120	0	2,995,792	0
5140000	Maintenance of Misc Steam Plt	1,155,915	1,155,915	0	578,917	0
5140025	Maint MiscStmPlt Environmental	(4)	(4)	0	(2)	0
	Steam Generation Maintenance	**31,045,811**	**31,045,811**	-	**12,835,396**	-
	Nuclear Generation Maintenance	-	-	-	-	-

American Electric Power

INCOME STATEMENT

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Layout: GLS8016

09B V2099-01-01	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Corp Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Company - Distribution 110 Actual YTD Dec 2013	Kentucky Power Company - Generation 117 Actual YTD Dec 2013	Kentucky Power Company - Transmission 180 Actual YTD Dec 2013
	Hydro Generation Maintenance	-	-	-	-	-
	Other Generation Maintenance	-	-	-	-	-
5680000	Maint Supv & Engineering	105,531	105,531	24	5	105,502
5690000	Maintenance of Structures	10,780	10,780	0	0	10,780
5691000	Maint of Computer Hardware	20,287	20,287	3	4	20,280
5692000	Maint of Computer Software	285,718	285,718	3,931	19	281,767
5693000	Maint of Communication Equip	26,018	26,018	0	0	26,018
5700000	Maint of Station Equipment	784,014	784,014	73,984	0	710,031
5710000	Maintenance of Overhead Lines	1,773,834	1,773,834	2,900	2	1,770,932
5730000	Maint of Misc Trnsmssion Plt	67,844	67,844	0	0	67,844
	Transmission Maintenance	**3,074,026**	**3,074,026**	**80,842**	**29**	**2,993,154**
5900000	Maint Supv & Engineering	1,589	1,589	1,579	1	9
5910000	Maintenance of Structures	32,058	32,058	21,203	0	10,855
5920000	Maint of Station Equipment	768,334	768,334	732,318	41	35,975
5930000	Maintenance of Overhead Lines	24,687,433	24,687,433	24,690,372	115	(3,055)
5930001	Tree and Brush Control	375,785	375,785	375,785	0	0
5930010	Storm Expense Amortization	4,698,444	4,698,444	4,698,444	0	0
5940000	Maint of Underground Lines	231,685	231,685	231,685	0	0
5950000	Maint of Lne Trnf,Rglators&Dvi	56,587	56,587	56,587	0	0
5960000	Maint of Strt Lghtng & Sgnal S	59,381	59,381	59,381	0	0
5970000	Maintenance of Meters	60,536	60,536	57,239	0	3,297
5980000	Maint of Misc Distribution Plt	121,720	121,720	121,710	0	10
	Distribution Maintenance	**31,093,552**	**31,093,552**	**31,046,304**	**157**	**47,091**
9350000	Maintenance of General Plant	0	0	0	0	0
9350001	Maint of Structures - Owned	367,763	367,763	359,473	2,927	2,276
9350002	Maint of Structures - Leased	55,655	55,655	55,657	(1)	(0)
9350003	Maint of Prprty Held Fture Use	40	40	0	0	0
9350013	Maint of Cmmncation Eq-Unall	850,753	850,753	779,285	50,338	0
9350015	Maint of Office Furniture & Eq	481,552	481,552	176,909	165,670	0
9350016	Maintenance of Video Equipment	784	784	496	158	0
9350019	Maint of Gen Plant-SCADA Equ	166	166	149	17	0
9350024	Maint of DA-AMI Comm Equip	6,787	6,787	6,787	0	0
	Administration & General Maintenance	**1,763,502**	**1,763,502**	**1,378,756**	**219,108**	**2,276**
	All Other Maintenance Expenses	-	-	-	-	-
	Maintenance Expenses	**66,976,890**	**66,976,890**	**32,505,902**	**13,054,691**	**3,042,521**
	Total Operational and Maintenance Expenses	**170,346,241**	**170,346,241**	**94,222,087**	**70,200,413**	**9,762,414**
	Memo: Operational and Sale of Property	***101,608,728***	***101,608,728***	***61,716,185***	***55,377,674***	***6,727,317***
4040001	Amort. of Plant	3,684,789	3,684,789	1,900,151	1,264,835	519,804
4060001	Amort of Plt Acq Adj	38,616	38,616	0	0	38,616
	DDA Amortization	**3,723,405**	**3,723,405**	**1,900,151**	**1,264,835**	**558,420**
4073000	Regulatory Debits	289,297	289,297	0	0	289,297
	DDA Regulatory Debits	**289,297**	**289,297**	-	-	**289,297**
	DDA Regulatory Credits	-	-	-	-	-
	Amortization	**4,012,702**	**4,012,702**	**1,900,151**	**1,264,835**	**847,717**
4030001	Depreciation Exp	87,625,312	87,625,312	24,528,320	20,440,046	8,752,449
4030020	Capacity Cost Ov-Und Depr Exp	(7,654,319)	(7,654,319)	0	0	0
	DDA Depreciation	**79,970,993**	**79,970,993**	**24,528,320**	**20,440,046**	**8,752,449**
	DDA STP Nuclear Decommissioning	-	-	-	-	-
4031001	Depr - Asset Retirement Oblig	53,837	53,837	0	0	0
	DDA Asset Retirement Obligation	**53,837**	**53,837**	-	-	-
	DDA Removal Costs	-	-	-	-	-
	Depreciation	**80,024,830**	**80,024,830**	**24,528,320**	**20,440,046**	**8,752,449**

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Layout: GLS8016

09B V2099-01-01	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Corp Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Company - Distribution 110 Actual YTD Dec 2013	Kentucky Power Company - Generation 117 Actual YTD Dec 2013	Kentucky Power Company - Transmission 180 Actual YTD Dec 2013
	Depreciation and Amortization	**84,037,532**	**84,037,532**	**26,428,471**	**21,704,881**	**9,600,166**
408100809	State Franchise Taxes	(130)	(130)	0	0	0
408100812	State Franchise Taxes	(9,494)	(9,494)	(1,203)	(2,156)	(5,761)
408100813	State Franchise Taxes	3,999	3,999	0	2,895	887
	Franchise Taxes	**(5,625)**	**(5,625)**	**(1,203)**	**739**	**(4,874)**
408100600	State Gross Receipts Tax	66,892	66,892	0	71,358	0
408100608	State Gross Receipts Tax	(16,558)	(16,558)	0	(12,336)	0
408100609	State Gross Receipts Tax	(30,322)	(30,322)	0	(26,747)	0
408100612	State Gross Receipts Tax	(45,492)	(45,492)	0	(31,461)	0
408100613	State Gross Receipts Tax	86,786	86,786	3	54,368	0
	Revenue-kWhr Taxes	**61,306**	**61,306**	**3**	**55,182**	**-**
4081002	FICA	3,031,455	3,031,455	1,536,986	664,806	263,097
4081003	Federal Unemployment Tax	56,278	56,278	30,315	11,963	5,212
4081007	State Unemployment Tax	63,241	63,241	30,075	11,784	5,056
4081033	Fringe Benefit Loading - FICA	(1,156,883)	(1,156,883)	(735,484)	(159,630)	(148,441)
4081034	Fringe Benefit Loading - FUT	(9,249)	(9,249)	(6,203)	(1,027)	(1,219)
4081035	Fringe Benefit Loading - SUT	(17,931)	(17,931)	(11,578)	(1,873)	(2,108)
	Payroll Taxes	**1,966,912**	**1,966,912**	**844,110**	**526,022**	**121,596**
408102013	State Business Occup Taxes	3,984,164	3,984,164	0	0	0
	Capacity Taxes	**3,984,164**	**3,984,164**	**-**	**-**	**-**
408100508	Real & Personal Property Taxes	811	811	805	0	6
408100510	Real Personal Property Taxes	66,347	66,347	47,220	3,209	15,918
408100511	Real Personal Property Taxes	1,391,423	1,391,423	126,087	(46,303)	(64,610)
408100512	Real Personal Property Taxes	11,369,610	11,369,610	5,740,819	857,598	3,341,193
408102911	Real-Pers Prop Tax-Cap Leases	(10,026)	(10,026)	(5,828)	(3,759)	(438)
408102912	Real-Pers Prop Tax-Cap Leases	(3,303)	(3,303)	(2,037)	(1,139)	(127)
408102913	Real-Pers Prop Tax-Cap Leases	17,300	17,300	13,146	1,135	3,019
408103613	Real Prop Tax-Cap Leases	27,000	27,000	27,000	0	0
408200512	Real Personal Property Taxes	58,651	58,651	9,588	2,051	47,012
	Property Taxes	**12,917,813**	**12,917,813**	**5,956,800**	**812,791**	**3,341,973**
408101812	St Publ Serv Comm Tax-Fees	515,095	515,095	515,095	0	0
408101813	St Publ Serv Comm Tax-Fees	473,122	473,122	473,122	0	0
	Regulatory Fees	**988,217**	**988,217**	**988,217**	**-**	**-**
408101413	Federal Excise Taxes	3,685	3,685	0	2,489	0
	Production Taxes	**3,685**	**3,685**	**-**	**2,489**	**-**
408101713	St Lic Rgstrtion Tax-Fees	908	908	60	0	0
408101900	State Sales and Use Taxes	342,470	342,470	156,655	178,775	7,040
408101912	State Sales and Use Taxes	1,109	1,109	1,109	0	0
408101913	State Sales and Use Taxes	11,175	11,175	11,170	4	0
408102213	Municipal License Fees	325	325	325	0	0
408102713	Misc State and Local Taxes	2	2	0	0	0
	Miscellaneous Taxes	**355,988**	**355,988**	**169,319**	**178,779**	**7,040**
	Other Non-Income Taxes	**359,673**	**359,673**	**169,319**	**181,269**	**7,040**
	Taxes Other Than Income Taxes	**20,272,460**	**20,272,460**	**7,957,247**	**1,576,002**	**3,465,735**
	TOTAL OPERATING EXPENSES	**274,656,233**	**274,656,233**	**128,607,804**	**93,481,296**	**22,828,315**
	Memo: SEC Total Operating Expenses	**744,477,032**	**744,477,032**	**498,642,885**	**481,350,933**	**22,828,315**
	OPERATING INCOME	**59,199,428**	**59,199,428**	**28,234,552**	**(35,057,218)**	**64,534,576**
	NON-OPERATING INCOME / (EXPENSES)					
4190002	Int & Dividend Inc - Nonassoc	118,167	118,167	68,419	(5,858)	55,606
	Interest & Dividend NonAffiliated	**118,167**	**118,167**	**68,419**	**(5,858)**	**55,606**

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INCOME STATEMENT

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		Kentucky Power Int Consol GLS8016 Actual	Kentucky Power Corp Consol GLS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		YTD Dec 2013	YTD Dec 2013	YTD Dec 2013	YTD Dec 2013	YTD Dec 2013
4190005	Interest Income - Assoc CBP	35,768	35,768	(37,302)	(199,311)	272,381
	Interest & Dividend Affiliated	**35,768**	**35,768**	**(37,302)**	**(199,311)**	**272,381**
	Total Interest & Dividend Income	**153,935**	**153,935**	**31,117**	**(205,168)**	**327,986**
4210039	Carrying Charges	76,948	76,948	0	0	76,948
	Interest & Dividend Carrying Charge	**76,948**	**76,948**	-	-	**76,948**
	Memo: Total Interest & Dividend Income w/ Carrying	**230,883**	**230,883**	**31,117**	**(205,168)**	**404,934**
4191000	Allw Oth Fnds Usd Drng Cnstr	1,366,601	1,366,601	340,896	52,510	973,195
	AFUDC	**1,366,601**	**1,366,601**	**340,896**	**52,510**	**973,195**
	Gain on Disposition of Equity Investments	-	-	-	-	-
	Interest LTD FMB	-	-	-	-	-
4270002	Int on LTD - Install Pur Contr	26,320	26,320	0	0	0
	Interest LTD IPC	**26,320**	**26,320**	-	-	-
4300001	Interest Exp - Assoc Non-CBP	1,050,000	1,050,000	367,189	378,767	304,044
	Interest LTD Notes Payable - Affiliated	**1,050,000**	**1,050,000**	**367,189**	**378,767**	**304,044**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-	-
	Interest LTD Debentures	-	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	43,582,040	43,582,040	12,754,641	11,232,156	10,011,909
	Interest LTD Senior Unsecured	**43,582,040**	**43,582,040**	**12,754,641**	**11,232,156**	**10,011,909**
	Interest LTD Other - Affil	-	-	-	-	-
4270005	Int on LTD - Other LTD	1,317,708	1,317,708	0	0	0
4270202	Int on LTD - Inst Pur C Contra	(26,320)	(26,320)	0	0	0
	Interest LTD Other - NonAffil	**1,291,388**	**1,291,388**	-	-	-
	Interest on Long-Term Debt	**45,949,748**	**45,949,748**	**13,121,831**	**11,610,922**	**10,315,953**
4300003	Int to Assoc Co - CBP	12,442	12,442	9,990	128,390	(125,938)
	Interest STD - Affil	**12,442**	**12,442**	**9,990**	**128,390**	**(125,938)**
4310007	Lines Of Credit	776,225	776,225	385,296	123,353	112,052
	Interest STD - NonAffil	**776,225**	**776,225**	**385,296**	**123,353**	**112,052**
	Interest on Short Term Debt	**788,667**	**788,667**	**395,286**	**251,743**	**(13,886)**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	720,576	720,576	176,766	155,666	138,755
	Amort of Debt Disc. Prem & Exp	**720,576**	**720,576**	**176,766**	**155,666**	**138,755**
4281004	Amrtz Loss Rcquired Debt-Dbnt	33,649	33,649	12,623	11,116	9,909
	Amort Loss on Reacquired Debt	**33,649**	**33,649**	**12,623**	**11,116**	**9,909**
	Amort Gain on Reacquired Debt	-	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-	-
4310001	Other Interest Expense	24,178	24,178	0	14,741	9,437
4310002	Interest on Customer Deposits	42,783	42,783	42,783	0	0
4310022	Interest Expense - Federal Tax	(7,981)	(7,981)	723	(3,843)	(4,861)
4310023	Interest Expense - State Tax	4,464	4,464	2,221	2,137	106
	Other Interest - NonAffil	**63,444**	**63,444**	**45,727**	**13,035**	**4,682**
	Other Interest Expense - Affil	-	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(3,047,349)	(3,047,349)	(237,777)	(36,792)	(676,161)
	AFUDC-Borrowed Funds	**(3,047,349)**	**(3,047,349)**	**(237,777)**	**(36,792)**	**(676,161)**
	Total Interest Charges	**44,508,734**	**44,508,734**	**13,514,457**	**12,005,690**	**9,779,251**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**16,288,179**	**16,288,179**	**15,092,109**	**(47,215,566)**	**56,133,454**
	INCOME TAXES and EQUITY EARNINGS					
4091001	Income Taxes, UOI - Federal	(193,245)	(193,245)	(1,088,997)	(7,034,759)	10,362,906
4092001	Inc Tax, Oth Inc&Ded-Federal	1,182,262	1,182,262	(8,652)	1,122,787	68,127
	Federal Current Income Tax	**989,017**	**989,017**	**(1,097,649)**	**(5,911,972)**	**10,431,033**
4101001	Prov Def I/T Util Op Inc-Fed	60,544,574	60,544,574	20,370,711	27,993,681	12,180,181
4102001	Prov Def I/T Oth I&D - Federal	(218,251)	(218,251)	17,524	6,589	11,984

American Electric Power

INCOME STATEMENT

GLS8016
YTD Dec 2013
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Layout: GLS8016

09B V2099-01-01	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Corp Consol GLS8016 Actual YTD Dec 2013	Kentucky Power Company - Distribution 110 Actual YTD Dec 2013	Kentucky Power Company - Generation 117 Actual YTD Dec 2013	Kentucky Power Company - Transmission 180 Actual YTD Dec 2013
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(43,410,193)	(43,410,193)	(14,929,053)	(24,751,758)	(3,729,382)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(12,724,980)	(12,724,980)	(75,726)	(12,633,781)	(15,473)
	Federal Deferred Income Tax	**4,191,150**	**4,191,150**	**5,383,457**	**(9,385,268)**	**8,447,310**
4114001	ITC Adj, Utility Oper - Fed	(230,012)	(230,012)	(38,749)	(51,103)	(140,159)
	Federal Investment Tax Credits	**(230,012)**	**(230,012)**	**(38,749)**	**(51,103)**	**(140,159)**
	Federal Income Taxes	**4,950,156**	**4,950,156**	**4,247,059**	**(15,348,343)**	**18,738,183**
409100212	Income Taxes UOI - State	(175,242)	(175,242)	(25,722)	(200,363)	50,843
409100213	Income Taxes UOI - State	2,415,966	2,415,966	747,341	(893,223)	2,618,954
409200212	Inc Tax Oth Inc Ded - State	(4,867)	(4,867)	(1,906)	(1,848)	(1,112)
409200213	Inc Tax Oth Inc Ded - State	208,126	208,126	320	193,640	14,167
	State Current Income Tax	**2,443,984**	**2,443,984**	**720,033**	**(901,794)**	**2,682,851**
	State Deferred Income Tax	-	-	-	-	-
	State Investment Tax Credits	-	-	-	-	-
	State Income Taxes	**2,443,984**	**2,443,984**	**720,033**	**(901,794)**	**2,682,851**
409100313	Income Tax UOI - Local	(12,129)	(12,129)	0	0	0
	Local Current Income Tax	**(12,129)**	**(12,129)**	-	-	-
	Local Deferred Income Tax	-	-	-	-	-
	Local Investment Tax Credits	-	-	-	-	-
	Local Income Taxes	**(12,129)**	**(12,129)**	-	-	-
	Foreign Current Income Tax	-	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-	-
	Foreign Income Taxes	-	-	-	-	-
	Total Income Taxes	**7,382,011**	**7,382,011**	**4,967,092**	**(16,250,137)**	**21,421,034**
	Equity Earnings of Subs	-	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**8,906,168**	**8,906,168**	**10,125,018**	**(30,965,429)**	**34,712,419**
	Discontinued Operations (Net of Taxes)	-	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-	-
	NET INCOME	**8,906,168**	**8,906,168**	**10,125,018**	**(30,965,429)**	**34,712,419**

AMERICAN ELECTRIC POWER COMPANY
GLS8216

BALANCE SHEET

YTD Dec 2013
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Layout : GLS8216

09B V2099-01- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Dec 2013	YTD Dec 2013	YTD Dec 2013	YTD Dec 2013
ASSETS				
Cash and Cash Equivalents	742,782	742,782	0	0
Other Cash Deposits	0	0	0	0
Customers	17,888,549	12,309,701	4,776,578	802,270
Accrued Unbilled Revenues	856,776	856,776	0	0
Miscellaneous Accounts Receivable	9,856,159	4,932,404	51,297,374	9,066,373
Allowances for Uncollectible Accounts	(77,562)	(77,562)	0	0
Accounts Receivable	28,523,922	18,021,319	56,073,952	9,868,643
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	136,253,647	2,261,757	85,472,788	807,299
Risk Management Contracts - Current	4,356,386	36,893	4,319,493	0
Margin Deposits	1,045,959	53,976	991,983	0
Unrecovered Fuel - Current	0	0	0	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	2,237,407	1,959,186	163,036	115,185
TOTAL CURRENT ASSETS	173,160,103	23,075,913	147,021,252	10,791,128
Electric Production	1,052,756,733	736,524,200	571,799,289	503,846,251
Electric Transmission	507,844,544	0	0	0
Electric Distribution	693,480,859	0	0	0
General Property, Plant and Equipment	480,758,822	199,571	1,535,563	1,160,479
Construction Work-in-Progress	128,599,148	12,638,869	4,978,744	35,728,716
TOTAL PROPERTY, PLANT and EQUIPMENT	2,863,440,106	749,362,640	578,313,596	540,735,446
less: Accumulated Depreciation and Amortization	(943,889,464)	(230,907,155)	(237,346,507)	(165,548,853)
NET PROPERTY, PLANT and EQUIPMENT	1,919,550,642	518,455,485	340,967,088	375,186,593
Net Regulatory Assets	216,359,696	103,145,781	25,050,542	54,801,281
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	3,483,625	0	3,483,625	0
Employee Benefits and Pension Assets	11,446,242	(1,372,567)	(174,524)	250,443
Other Non Current Assets	20,202,653	7,706,497	2,067,001	4,367,286
TOTAL OTHER NON-CURRENT ASSETS	251,492,216	109,479,711	30,426,644	59,419,011
TOTAL ASSETS	2,344,202,961	651,011,109	518,414,985	445,396,731
LIABILITIES				
Accounts Payable	60,789,783	62,742,356	48,612,333	4,875,087
Advances from Affiliates	8,564,457	(2,004,073)	138,447,512	(127,878,981)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0

AMERICAN ELECTRIC POWER COMPANY
GLS8216

BALANCE SHEET

YTD Dec 2013
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Layout : GLS8216

09B V2099-01- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS		Kentucky Power Int Consol GLS8216 YTD Dec 2013	Kentucky Power Company - 110 YTD Dec 2013	Kentucky Power Company - Generation 117 YTD Dec 2013	Kentucky Power Company - 180 YTD Dec 2013
	Long-Term Debt Due Within One Year Non-Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities	**1,827,628**	**0**	**1,827,628**	**0**
	Accrued Taxes	**15,552,699**	**8,259,360**	**(5,436,626)**	**8,554,965**
	Memo: Property Taxes	19,689,629	9,172,839	881,989	5,459,801
	Accrued Interest	**6,677,502**	**2,656,392**	**1,941,948**	**2,019,787**
	Risk Management Collateral	840,867	0	840,867	0
	Utility Customer Deposits	24,370,419	24,370,419	0	0
	Deposits - Customer and Collateral	**25,211,285**	**24,370,419**	**840,867**	**0**
	Over-Recovered Fuel Costs - Current	**2,850,638**	**0**	**2,850,638**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	989,539	396,047	491,508	101,984
	Tax Collections Payable	2,193,334	2,163,813	20,187	9,333
	Revenue Refunds - Accrued	1,378,946	0	259,350	1,119,596
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	712,092	456,076	178,222	77,795
	Accrued Rents	0	0	0	0
	Accrued ICP	3,579,700	2,200,358	988,481	390,861
	Accrued Vacations	3,079,667	1,959,238	793,540	326,889
	Misc Employee Benefits	1,039,485	475,437	301,836	21,945
	Payroll Deductions	155,889	95,904	41,745	18,240
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	684,514	447,427	94,394	39,536
2530022	Customer Advance Receipts	1,986,684	1,986,684	0	0
	Customer Advance	1,986,684	1,986,684	0	0
	Control Cash Disbursement Account	1,681,797	1,681,797	0	0
	JMG Liability	0	0	0	0
2420087	Engage to Gain Incentive	421,265	273,097	102,833	45,335
2420088	Econ. Development Fund Curr	233,000	0	233,000	0
2420512	Unclaimed Funds	4,133	4,133	0	0
2420542	Acc Cash Franchise Req	76,324	76,324	0	0
242059213	Sales Use Tax - Lease Equip	9,259	9,142	43	75
2420643	Accrued Audit Fees	40,270	338	39,729	203
2420656	Federal Mitigation Accru (NSR)	554,326	0	376,794	0
2420664	ST State Mitigation Def (NSR)	279,106	0	189,717	0
2530050	Deferred Rev -Pole Attachments	90,828	90,828	0	0
2530112	Other Deferred Credits-Curr	221,616	0	221,616	0
	Misc Current and Accrued Liabilities	1,930,128	453,862	1,163,733	45,613
	Current Other and Accrued Liabilities	18,422,237	11,920,595	3,841,489	2,049,808
	Other Current Liabilities	**19,411,776**	**12,316,642**	**4,332,997**	**2,151,792**
	TOTAL CURRENT LIABILITIES	**140,885,769**	**108,341,096**	**193,417,296**	**(110,277,351)**
	Long-Term Debt - Affiliated	**20,000,000**	**7,949,800**	**5,883,600**	**6,166,600**

AMERICAN ELECTRIC POWER COMPANY
GLS8216

BALANCE SHEET

YTD Dec 2013
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Layout : GLS8216

09B V2099-01-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Dec 2013	Kentucky Power Company - 110 YTD Dec 2013	Kentucky Power Company - Generation 117 YTD Dec 2013	Kentucky Power Company 180 YTD Dec 2013
	Long-Term Debt - Non Affiliated	**730,000,000**	**210,669,700**	**155,915,400**	**163,414,900**
	Long-Term Debt - Premiums and Discounts Unamort	(611,325)	(242,996)	(179,840)	(188,490)
	Memo - LTD NonAffiliated and Premiums	*729,388,675*	*210,426,704*	*155,735,560*	*163,226,410*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	2,148,367	0	2,148,367	0
2440022	L/T Liability MTM Collateral	(43,369)	0	(43,369)	0
	Long-Term Risk Management Liabilities - MTM	2,104,998	0	2,104,998	0
	Long-Term Risk Management Liabilities	**2,104,998**	**0**	**2,104,998**	**0**
	Deferred Income Taxes	**556,157,782**	**166,258,936**	**81,800,706**	**116,964,220**
	Deferred Investment Tax Credits	**125,747**	**24,165**	**37,828**	**63,755**
	Regulatory Liabilities and Deferred Credits	**22,800,132**	(30,601,192)	**59,644,767**	(6,243,443)
	Memo - Reg Liab and Def ITC	*22,925,879*	*(30,577,027)*	*59,682,594*	*(6,179,688)*
	Asset Retirement Obligation	**20,526,045**	**60,944**	**4,043,636**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**6,040,775**	**3,205,747**	**1,391,569**	**56,634**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Rede	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	3,420,143	1,035,940	1,946,626	437,577
	Def Credits - Income Tax	679,196	360,765	275,890	42,541
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	754,942	0
	Def Credits - NSR	1,110,644	0	754,942	0
2520000	Customer Adv for Construction	112,133	112,133	0	0
	Customer Advances for Construction	112,133	112,133	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	7,346	0	7,346	0
2530004	Allowances	12,900	0	12,900	0
2530067	IPP - System Upgrade Credits	268,842	0	0	268,842
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	156,932	156,932	0	0
2530101	MACSS Unidentified EDI Cash	239	239	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	103,174	0	0	103,174
	Def Credits - Other	549,433	157,171	20,246	372,016
	Total Other Deferred Credits	661,566	269,304	20,246	372,016
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	932,000	0	932,000	0
	Other Non-Current Liabilities	**6,803,548**	**1,666,008**	**3,929,704**	**852,134**
	TOTAL NON-CURRENT LIABILITIES	**1,363,947,702**	**358,991,113**	**314,572,367**	**281,086,310**
	TOTAL LIABILITIES	**1,504,833,471**	**467,332,209**	**507,989,663**	**170,808,959**
	Cumulative Pref Stocks of Subs - Not subject Mand Reder	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**

COMMON SHAREHOLDERS' EQUITY

AMERICAN ELECTRIC POWER COMPANY
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BALANCE SHEET

YTD Dec 2013
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Layout : GLS8216

09B V2099-01- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Dec 2013	Kentucky Power Company - 110 YTD Dec 2013	Kentucky Power Company - Generation 117 YTD Dec 2013	Kentucky Power Company - 180 YTD Dec 2013
Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
Paid In Capital	**614,648,268**	**106,025,371**	**48,684,793**	**84,039,836**
Premium on Capital Stock	**0**	**0**	**0**	**0**
Retained Earnings	**179,690,924**	**55,313,124**	(48,480,098)	**172,857,898**
Accumulated Other Comprehensive Income (Loss)	(5,419,702)	(63,644)	(66,976)	(68,309)
TOTAL SHAREHOLDERS' EQUITY	**839,369,490**	**183,678,901**	**10,425,321**	**274,587,772**
Memo: Total Equity	839,369,490	183,678,901	10,425,321	274,587,772
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**2,344,202,961**	**651,011,109**	**518,414,985**	**445,396,731**

AMERICAN ELECTRIC POWER COMPANY
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BALANCE SHEET

YTD Dec 2012
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Layout : GLS8216

09B V2099-01- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Dec 2012	Kentucky Power Company - 110 YTD Dec 2012	Kentucky Power Company - Generation 117 YTD Dec 2012	Kentucky Power Company 180 YTD Dec 2012
ASSETS				
Cash and Cash Equivalents	1,481,978	1,481,978	0	0
Other Cash Deposits	0	0	0	0
Customers	25,825,998	7,954,139	6,693,246	1,018,421
Accrued Unbilled Revenues	4,471,700	816,940	0	0
Miscellaneous Accounts Receivable	53,533,735	30,792,765	49,708,084	22,384,683
Allowances for Uncollectible Accounts	(163,315)	(141,538)	0	0
Accounts Receivable	83,668,119	39,422,305	56,401,330	23,403,104
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	137,022,894	2,091,348	91,343,093	774,015
Risk Management Contracts - Current	6,174,820	11,102	6,163,718	0
Margin Deposits	1,920,501	32,003	1,888,498	0
Unrecovered Fuel - Current	0	0	0	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	4,870,790	1,635,895	2,958,625	111,195
TOTAL CURRENT ASSETS	235,139,101	44,674,631	158,755,264	24,288,315
Electric Production	1,438,998,684	697,175,919	567,653,334	494,324,126
Electric Transmission	495,980,929	0	0	0
Electric Distribution	652,615,329	0	0	0
General Property, Plant and Equipment	65,150,194	199,571	4,370,046	1,129,887
Construction Work-in-Progress	87,923,832	16,900,690	2,595,021	24,785,581
TOTAL PROPERTY, PLANT and EQUIPMENT	2,740,668,967	714,276,179	574,618,401	520,239,594
less: Accumulated Depreciation and Amortization	(884,015,657)	(216,698,508)	(225,580,674)	(161,094,165)
NET PROPERTY, PLANT and EQUIPMENT	1,856,653,310	497,577,671	349,037,727	359,145,429
Net Regulatory Assets	213,734,008	122,949,981	34,817,970	55,966,057
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	6,881,655	0	6,881,655	0
Employee Benefits and Pension Assets	0	0	0	0
Other Non Current Assets	54,985,194	5,971,833	39,281,491	3,626,788
TOTAL OTHER NON-CURRENT ASSETS	275,600,857	128,921,814	80,981,116	59,592,845
TOTAL ASSETS	2,367,393,268	671,174,116	588,774,107	443,026,589
LIABILITIES				
Accounts Payable	131,699,742	80,227,856	76,263,880	7,393,486
Advances from Affiliates	13,358,856	7,105,706	104,833,217	(98,580,067)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0

AMERICAN ELECTRIC POWER COMPANY
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YTD Dec 2012
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Layout : GLS8216

09B V2099-01- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS		Kentucky Power Int Consol GLS8216 YTD Dec 2012	Kentucky Power Company - 110 YTD Dec 2012	Kentucky Power Company - Generation 117 YTD Dec 2012	Kentucky Power Company - 180 YTD Dec 2012
	Long-Term Debt Due Within One Year Non-Affiliated	**250,000,000**	**0**	**0**	**0**
	Long-Term Debt Due Within One Year - Affiliated	**0**	**0**	**0**	**0**
	Risk Management Liabilities	**3,320,068**	**0**	**3,320,068**	**0**
	Accrued Taxes	**11,463,832**	**3,961,068**	**(2,541,236)**	**5,212,007**
	Memo: Property Taxes	15,302,594	4,697,887	3,158,849	3,209,609
	Accrued Interest	**12,001,656**	**3,257,419**	**1,877,295**	**2,075,275**
	Risk Management Collateral	101,978	0	101,978	0
	Utility Customer Deposits	23,382,987	23,382,987	0	0
	Deposits - Customer and Collateral	**23,484,965**	**23,382,987**	**101,978**	**0**
	Over-Recovered Fuel Costs - Current	**7,928,323**	**0**	**7,928,323**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	1,728,601	992,833	182,542	228,501
	Tax Collections Payable	2,111,104	2,033,137	19,621	8,469
	Revenue Refunds - Accrued	3,799,625	1,635,430	14,645	2,149,551
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	978,919	381,315	169,470	66,770
	Accrued Rents	0	0	0	0
	Accrued ICP	6,351,443	2,501,011	1,112,903	367,160
	Accrued Vacations	4,685,628	1,904,394	864,374	329,704
	Misc Employee Benefits	1,323,281	780,990	249,175	27,832
	Payroll Deductions	201,926	83,581	41,869	18,881
	Severance / SEI	463,981	258,527	85,039	120,415
	Accrued Workers Compensation	690,580	301,886	103,149	20,508
2530022	Customer Advance Receipts	2,634,498	2,634,498	0	0
	Customer Advance	2,634,498	2,634,498	0	0
2420511	Control Cash Disburse Account	1,998,024	1,998,024	0	0
	Control Cash Disbursement Account	1,998,024	1,998,024	0	0
	JMG Liability	0	0	0	0
2420512	Unclaimed Funds	3,657	3,657	0	0
2420542	Acc Cash Franchise Req	80,393	80,393	0	0
242059212	Sales Use Tax - Leased Equip	14,374	1,948	4,592	7,834
2420643	Accrued Audit Fees	3,647	1,610	1,086	950
2420656	Federal Mitigation Accru (NSR)	550,544	0	376,794	0
2420664	ST State Mitigation Def (NSR)	668,155	0	457,288	0
2530050	Deferred Rev -Pole Attachments	78,940	78,940	0	0
2530112	Other Deferred Credits-Curr	1,113,327	125,354	987,973	0
	Misc Current and Accrued Liabilities	2,513,037	291,902	1,827,733	8,785
	Current Other and Accrued Liabilities	27,752,047	14,804,694	4,487,978	3,118,074
	Other Current Liabilities	**29,480,648**	**15,797,526**	**4,670,520**	**3,346,575**
	TOTAL CURRENT LIABILITIES	**482,738,090**	**133,732,562**	**196,454,046**	**(80,552,724)**
	Long-Term Debt - Affiliated	**20,000,000**	**6,907,200**	**7,335,600**	**5,757,200**
	Long-Term Debt - Non Affiliated	**530,000,000**	**197,753,600**	**176,839,800**	**155,406,600**

AMERICAN ELECTRIC POWER COMPANY
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BALANCE SHEET

YTD Dec 2012
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Layout : GLS8216

09B V2099-01-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Dec 2012	Kentucky Power Company - 110 YTD Dec 2012	Kentucky Power Company - Generation 117 YTD Dec 2012	Kentucky Power Company - 180 YTD Dec 2012
	Long-Term Debt - Premiums and Discounts Unamort	(804,717)	(290,306)	(259,604)	(228,140)
	Memo - LTD NonAffiliated and Premiums	*529,195,283*	*197,463,294*	*176,580,196*	*155,178,460*
2450011	L/T Liability-Commodity Hedges	82,731	0	82,731	0
	Long-Term Risk Management Liabilities - Hedge	82,731	0	82,731	0
2440002	LT Unreal Losses - Non Affil	4,200,196	0	4,200,196	0
2440022	L/T Liability MTM Collateral	(582,545)	0	(582,545)	0
	Long-Term Risk Management Liabilities - MTM	3,617,651	0	3,617,651	0
	Long-Term Risk Management Liabilities	**3,700,382**	**0**	**3,700,382**	**0**
	Deferred Income Taxes	**505,522,745**	**158,056,358**	**89,978,166**	**107,413,593**
	Deferred Investment Tax Credits	**355,759**	**62,914**	**88,931**	**203,914**
	Regulatory Liabilities and Deferred Credits	**25,803,164**	(26,719,679)	**57,506,079**	(4,983,236)
	Memo - Reg Liab and Def ITC	*26,158,922*	*(26,656,765)*	*57,595,010*	*(4,779,322)*
	Asset Retirement Obligation	**8,759,164**	**57,546**	**3,844,713**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**32,386,979**	**19,587,227**	**9,829,651**	**1,563,914**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Rede	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	3,128,523	801,440	604,497	268,363
	Def Credits - Income Tax	1,286,428	370,015	876,869	39,545
2530114	Federl Mitigation Deferal(NSR)	1,103,065	0	754,942	0
	Def Credits - NSR	1,103,065	0	754,942	0
2520000	Customer Adv for Construction	63,178	63,178	0	0
	Customer Advances for Construction	63,178	63,178	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	260,280	0	0	260,280
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	162,614	162,614	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	116,729	0	0	116,729
	Def Credits - Other	539,623	162,614	0	377,009
	Total Other Deferred Credits	602,801	225,792	0	377,009
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**6,120,817**	**1,397,247**	**2,236,308**	**684,917**
	TOTAL NON-CURRENT LIABILITIES	**1,131,844,293**	**356,812,107**	**351,100,025**	**265,818,762**
	TOTAL LIABILITIES	**1,614,582,383**	**490,544,669**	**547,554,070**	**185,266,038**
	Cumulative Pref Stocks of Subs - Not subject Mand Reder	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**531,535,595**	**106,025,371**	**48,684,793**	**84,039,836**
	Premium on Capital Stock	**0**	**0**	**0**	**0**

AMERICAN ELECTRIC POWER COMPANY
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BALANCE SHEET

YTD Dec 2012
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Layout : GLS8216

09B V2099-01- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Dec 2012	Kentucky Power Company - 110 YTD Dec 2012	Kentucky Power Company - Generation 117 YTD Dec 2012	Kentucky Power Company - 180 YTD Dec 2012
Retained Earnings	**190,818,916**	**52,287,148**	(17,514,669)	**156,046,437**
Accumulated Other Comprehensive Income (Loss)	(19,993,625)	(87,121)	(237,690)	(84,070)
TOTAL SHAREHOLDERS' EQUITY	**752,810,885**	**180,629,447**	**41,220,037**	**257,760,551**
Memo: Total Equity	752,810,885	180,629,447	41,220,037	257,760,551
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**2,367,393,268**	**671,174,116**	**588,774,107**	**443,026,589**

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - December, 2013

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	559,731,713.30	6,493,136.08	(4,682,379.19)	0.00	0.00	561,542,470.19
	TOTAL PRODUCTION	**559,731,713.30**	**6,493,136.08**	**(4,682,379.19)**	**0.00**	**0.00**	**561,542,470.19**
101/106	TRANSMISSION	493,489,120.26	14,626,518.47	(4,950,066.93)	0.00	0.00	503,165,571.80
101/106	DISTRIBUTION	693,312,997.44	53,375,152.46	(12,911,559.09)	0.00	0.00	733,776,590.81
	TOTAL (ACCOUNTS 101 & 106)	**1,746,533,831.00**	**74,494,807.01**	**(22,544,005.21)**	**0.00**	**0.00**	**1,798,484,632.80**
1011001/12	CAPITAL LEASES	5,182,997.28	0.00	0.00	1,096,151.89	0.00	6,279,149.17
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**1,751,716,828.28**	**74,494,807.01**	**(22,544,005.21)**	**1,096,151.89**	**0.00**	**1,804,763,781.97**
1050001	PLANT HELD FOR FUTURE USE	7,436,550.73	0.00	0.00	0.00	(30,592.00)	7,405,958.73
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEG. BAL.	44,281,291.91					
107000X	ADDITIONS		83,559,844.20				
107000X	TRANSFERS		(74,494,807.01)				
107000X	END. BAL.		9,065,037.19				53,346,329.10
	TOTAL ELECTRIC UTILITY PLANT	**1,803,434,670.92**	**83,559,844.20**	**(22,544,005.21)**	**1,096,151.89**	**(30,592.00)**	**1,865,516,069.80**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	964,528.00	0.00	0.00	0.00	30,592.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,734,975.63	0.00	(2,834,483.00)	0.00	0.00	1,900,492.63
	TOTAL NONUTILITY PLANT	**5,699,503.63**	**0.00**	**(2,834,483.00)**	**0.00**	**30,592.00**	**2,895,612.63**

Prepared by: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee -- Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - December, 2013

GLR7410V 01/10/14 07:14

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	273,621,070.97	20,629,667.16	(3,385,788.60)	(1,447,771.13)	0.00	289,417,178.40
1080001/11	TRANSMISSION	157,337,333.70	8,752,449.22	(4,771,201.12)	219,213.36	0.00	161,537,795.16
1080001/11	DISTRIBUTION	179,721,144.51	24,533,952.48	(9,027,613.25)	(2,482,823.10)	0.00	192,744,660.64
1080013	PRODUCTION	(3,095,458.61)	0.00	0.00	0.00	(524,556.65)	(3,620,015.26)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(17,669.03)	0.00	0.00	0.00	(9,029.82)	(26,698.85)
	RETIREMENT WORK IN PROGRESS	(6,326,680.62)	0.00	0.00	(5,704,952.77)	3,711,380.87	(8,320,252.52)
	TOTAL (108X accounts)	**601,239,740.93**	**53,916,068.86**	**(17,184,602.97)**	**(9,416,333.64)**	**3,177,794.40**	**631,732,667.58**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,461,106.71	1,264,834.75	(1,296,590.59)	0.00	0.00	10,429,350.87
1110001	TRANSMISSION	1,266,854.71	519,803.78	(178,865.81)	0.00	0.00	1,607,792.68
1110001	DISTRIBUTION	9,166,379.72	1,900,150.87	(3,883,945.84)	0.00	0.00	7,182,584.75
	TOTAL (111X accounts)	**20,894,341.14**	**3,684,789.40**	**(5,359,402.24)**	**0.00**	**0.00**	**19,219,728.30**
1011006	CAPITAL LEASES	2,104,820.44	0.00	0.00	0.00	(235,353.35)	1,869,467.09
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**624,238,902.51**	**57,600,858.26**	**(22,544,005.21)**	**(9,416,333.64)**	**2,942,441.05**	**652,821,862.97**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	208,286.03	6,669.72	0.00	0.00	0.00	214,955.75
1240027	Other Property - RWIP	(7,500.00)	0.00	0.00	(2,834,483.00)	2,838,583.00	(3,400.00)
1240028	Other Property - RETIRE	0.00	0.00	(2,834,483.00)	2,834,483.00	0.00	0.00
	TOTAL NONUTILITY PLANT	**200,786.03**	**6,669.72**	**(2,834,483.00)**	**0.00**	**2,838,583.00**	**211,555.75**

Prepared By: PSnVision Report GLR7410V
Reviewer: Cindy Buckbee – Prop Acctg. Canton
Sources of Info: PowerPlant Reports and PS GL

AEP AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

January 30, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed Form EIA-826, Monthly Electric Utility Sales and Revenue Report with State Distributions for the month of December 2013.

Sincerely,

Brian J. Frantz

Brian J. Frantz
Manager –Regulated Accounting

BJF
Enclosure

U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2013

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585, and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**
Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650

Utility Name: Kentucky Power Company | **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan__ Feb__ Mar__ Apr__ May__ Jun__ Jul__ Aug__ Sep__ Oct__ Nov__ Dec_X_, 2013

Contact Person: Ronald F Davis | **Phone number: 614-716-3525**
Email: rdavis@aep.com | **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 23,648	$ 10,128	$ 12,715		$ 46,491
	b. Megawatthours	261,079	108,661	231,529		601,269
	c. Number of consumers	140,119	30,732	1,301		172,152
	a. Revenue (Thousand Dollars)					
	b. Megawatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megawatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megawatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megawatthours					
	c. Number of consumers					

Note

AEP
AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

February 27, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed January 2014 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:	
1-8	Income Statement
1-3	Details of Operating Revenues
4-7	Operating Expenses – Functional Expenses
8	Detail Statement of Taxes
Balance Sheet:	
9	Balance Sheet – Assets & Other Debits
9-11	Balance Sheet – Liabilities & Other Credits
10	Deferred Credits
11	Statement of Retained Earnings
Utility Property:	
12-13	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Brian J. Frantz
Manager – Regulated Accounting

BJF

Enclosure
Cc: Lila Munsey (w/pages)

American Electric Power

GLS8016
YTD Jan 2014
02/11/2014 11:39

INCOME STATEMENT

Layout: GLS8016
09B V2099-01-01 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Jan 2014	Kentucky Power Company - Distribution 110 Actual YTD Jan 2014	Kentucky Power Company - Generation 117 Actual YTD Jan 2014	Kentucky Power Company - Transmission 180 Actual YTD Jan 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	16,572,014	16,539,067	32,947	0
4400002		Residential Sales-W/O Space Ht	6,184,589	6,172,334	12,255	0
4400005		Residential Fuel Rev	9,822,327	9,822,327	0	0
	A	**Revenue - Residential Sales**	**32,578,930**	**32,533,728**	**45,202**	-
4420001		Commercial Sales	7,486,358	7,257,954	228,404	0
4420006		Sales to Pub Auth - Schools	1,335,373	1,292,430	42,943	0
4420007		Sales to Pub Auth - Ex Schools	1,381,712	1,338,525	43,187	0
4420013		Commercial Fuel Rev	4,041,779	4,041,779	0	0
	A	**Revenue - Commercial Sales**	**14,245,222**	**13,930,688**	**314,534**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	5,648,017	5,408,906	239,111	0
4420004		Ind Sales-NonAffil(Incl Mines)	2,624,287	2,523,376	100,910	0
4420016		Industrial Fuel Rev	7,432,151	7,432,151	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**15,704,455**	**15,364,434**	**340,021**	-
		Revenue - Industrial Sales	**15,704,455**	**15,364,434**	**340,021**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	122,435	116,541	5,893	0
4440002		Public St & Hwy Light Fuel Rev	33,778	33,778	0	0
	A	**Revenue - Other Retail Sales**	**156,213**	**150,319**	**5,893**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**62,684,820**	**61,979,170**	**705,650**	-
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	3,707,100
4561033		PJM NITS Revenue - Affiliated	3,119,037	0	0	3,119,037
4561034		PJM TO Adm Serv Rev - Aff	0	0	0	59,902
4561035		PJM Affiliated Trans NITS Cost	(3,105,532)	0	(3,105,532)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(59,902)	0
4561059		Affl PJM Trans Enhancmnt Rev	27,283	0	0	27,283
4561060		Affl PJM Trans Enhancmnt Cost	(27,165)	0	(27,165)	0
4561062		PROVISION PJM NITS Affil Cost	(63,395)	0	(63,395)	0
4561063		PROVISION PJM NITS Affiliated	(18,340)	0	0	(18,340)
	B	**Revenue - Transmission-Affiliated**	**(68,112)**	-	**(3,255,994)**	**6,894,981**
4470150		Transm Rev - Dedic Whlsl/Muni	4,775	0	(56,845)	61,619
4470206		PJM Trans loss credits-OSS	537,368	0	537,368	0
4470207		PJM transm loss charges - LSE	(5,320,266)	0	(5,320,266)	0
4470208		PJM Transm loss credits-LSE	929,407	0	929,407	0
4470209		PJM transm loss charges-OSS	(3,684,422)	0	(3,684,422)	0
4561002		RTO Formation Cost Recovery	(931)	0	(13,366)	12,435
4561003		PJM Expansion Cost Recov	6,036	0	(8,050)	14,086
4561005		PJM Point to Point Trans Svc	69,853	0	69,853	0
4561006		PJM Trans Owner Admin Rev	23,848	0	0	23,848
4561007		PJM Network Integ Trans Svc	1,223,314	0	0	1,223,314
4561019		Oth Elec Rev Trans Non Affil	7,611	0	0	7,611
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	601	0	0	601
4561029		PJM NITS Revenue Whsl Cus-NAff	230,686	0	0	230,686
4561030		PJM TO Serv Rev Whls Cus-NAff	3,739	0	0	3,739
4561058		NonAffil PJM Trans Enhncmt Rev	27,779	0	0	27,779
4561061		NAff PJM RTEP Rev for Whsl FR	2,018	0	0	2,018
4561064		PROVISION PJM NITS WhslCus-NAf	(1,187)	0	0	(1,187)
4561065		PROVISION PJM NITS	(6,713)	0	0	(6,713)
	A	**Revenue - Transmission-NonAffiliated**	**(5,946,484)**	-	**(7,546,320)**	**1,599,836**
		Revenue - Transmission	**(6,014,596)**	-	**(10,802,313)**	**8,494,817**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	9,531	0	9,531	0
4470128		Sales for Res-Aff Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,488,789**	-	**5,488,789**	-
4470002		Sales for Resale - NonAssoc	206,249	0	206,249	0
4470006		Sales for Resale-Bookout Sales	1,697,195	0	1,697,195	0
4470010		Sales for Resale-Bookout Purch	(3,004,446)	0	(3,004,446)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	328,065	0	328,065	0
4470028		Sale/Resale - NA - Fuel Rev	(211,165)	0	(211,165)	0
4470033		Whsal/Muni/Pub Auth Base Rev	276,064	0	276,064	0
4470066		PWR Trding Trans Exp-NonAssoc	(113)	0	(113)	0
4470081		Financial Spark Gas - Realized	2,572	0	2,572	0
4470082		Financial Electric Realized	1,386,305	0	1,386,305	0
4470089		PJM Energy Sales Margin	35,447,973	0	35,447,973	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jan 2014
02/11/2014 11:39

Layout: GLS8016
09B V2099-01-01 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Jan 2014	Kentucky Power Company - Distribution 110 Actual YTD Jan 2014	Kentucky Power Company - Generation 117 Actual YTD Jan 2014	Kentucky Power Company - Transmission 180 Actual YTD Jan 2014
4470093		PJM Implicit Congestion-LSE	(12,728,002)	0	(12,728,002)	0
4470098		PJM Oper Reserve Rev-OSS	(1,460,919)	0	(1,460,919)	0
4470099		Capacity Cr. Net Sales	52,464	0	52,464	0
4470100		PJM FTR Revenue-OSS	969	0	969	0
4470101		PJM FTR Revenue-LSE	3,816,850	0	3,816,850	0
4470103		PJM Energy Sales Cost	19,821,812	0	19,821,812	0
4470106		PJM Pt2Pt Trans Purch-NonAff	(15)	0	(15)	0
4470107		PJM NITS Purch-NonAff	929	0	929	0
4470109		PJM FTR Revenue-Spec	(210,346)	0	(210,346)	0
4470110		PJM TO Admin. Exp.-NonAff	(176)	0	(176)	0
4470115		PJM Meter Corrections-OSS	(10,205)	0	(10,205)	0
4470116		PJM Meter Corrections-LSE	30,326	0	30,326	0
4470124		PJM Incremental Spot-OSS	0	0	0	0
4470126		PJM Incremental Imp Cong-OSS	(12,969,559)	0	(12,969,559)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	49	0	49	0
4470144		Realiz Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim. Margin Reclass	(175)	0	(175)	0
4470170		Non-ECR Auction Sales-OSS	333,803	0	333,803	0
4470174		PJM Whlse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	65,562	0	65,562	0
4470176		OSS Sharing Reclass Reduction	(65,562)	0	(65,562)	0
4470180		Trading intra-book Reclass	(78,477)	0	(78,477)	0
4470181		Auction intra-book Reclass	78,477	0	78,477	0
4470202		PJM OpRes-LSE-Credit	355,360	0	355,360	0
4470203		PJM OpRes-LSE-Charge	(2,725,436)	0	(2,725,436)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,173	0	28,173	0
4470220		PJM Regulation - OSS	93,524	0	93,524	0
4470221		PJM Spinning Reserve - OSS	7	0	7	0
4470222		PJM Reactive - OSS	339	0	339	0
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	(9,217)	0	(9,217)	0
5550080		PJM Hourly Net Purch - FERC	(6,966,798)	0	(6,966,798)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**23,584,070**	**-**	**23,584,070**	**-**
	A	**Revenue - Resale-Realized**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt MTM**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt Activities**	**-**	**-**	**-**	**-**
		Revenue - Sales for Resale	**29,072,859**	**-**	**29,072,859**	**-**
4470074		Sale for Resale-Aff-Trnf Price	0	0	43,994,390	0
4540001		Rent From Elect Property - Af	25,947	78,632	0	0
	B	**Revenue - Other Ele-Affiliated**	**25,947**	**78,632**	**43,994,390**	**-**
4500000		Forfeited Discounts	377,161	377,161	0	0
4510001		Misc Service Rev - Nonaffil	19,625	18,496	0	1,130
4540002		Rent From Elect Property-NAC	150	150	0	0
4540005		Rent from Elec Prop-Pole Attch	409,234	409,234	0	0
4560007		Oth Elect Rev - DSM Program	640,109	640,109	0	0
		Revenue - Other Ele-NonAffiliated	**1,446,279**	**1,445,150**	**-**	**1,130**
		Revenue - Gas	**-**	**-**	**-**	**-**
4118004		Comp. Allow. Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,533**	**-**	**8,533**	**-**
	A	**Revenue - Other Ele-NonAffiliated**	**1,454,812**	**1,445,150**	**8,533**	**1,130**
		Revenue - Other Opr Electric	**1,480,759**	**1,523,781**	**44,002,922**	**1,130**
	D	**Revenue Merchandising & Contract Work**	**-**	**-**	**-**	**-**
	C	**Revenues Non-Utility Operations - Affiliated**	**-**	**-**	**-**	**-**
	D	**Revenues Non-Utility Operations - NonAffiliated**	**-**	**-**	**-**	**-**
		Revenues from Non-Utility Operations	**-**	**-**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	**-**	**-**	**-**	**-**
4180001		Non-Operating Rental Income	2,600	2,500	100	0
4180005		Non-Oprating Rntal Inc-Depr	(556)	0	0	(556)
	D	**Non-Operating Rental Income - NonAffiliated**	**2,044**	**2,500**	**100**	**(556)**
		Non-Operating Rental Income	**2,044**	**2,500**	**100**	**(556)**
	C	**Non-Operating Misc Income -Affiliated**	**-**	**-**	**-**	**-**
4210002		Misc Non-Op Inc-NonAsc-Rents	139	59	43	37
4210007		Misc Non-Op Inc - NonAsc - Oth	84	62	22	0
	D	**Non-Operating Misc Income - NonAffiliated**	**223**	**121**	**65**	**37**
		Non-Operating Misc Income	**223**	**121**	**65**	**37**
4540004		Rent From Elect Prop-ABD-Nonaf	7,645	7,645	0	0

Page 3

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jan 2014
02/11/2014 11:39

Layout: GLS8016
098 V2099-01-01 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Jan 2014	Kentucky Power Company - Distribution 110 Actual YTD Jan 2014	Kentucky Power Company - Generation 117 Actual YTD Jan 2014	Kentucky Power Company - Transmission 180 Actual YTD Jan 2014
4560015		Other Electric Revenues - ABD	8,055	15,245	0	(7,190)
	D	**Associated Business Development Income**	**15,700**	**22,890**	-	**(7,190)**
		Revenue - Other Opr - Other	**17,967**	**25,511**	**165**	**(7,709)**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***17,967***	***25,511***	***165***	***(7,709)***
		Revenue - Other Operating	**1,498,726**	**1,549,293**	**44,003,087**	**(6,579)**
	A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	-	-	-	-
4210032		Pwr Purch Outside Svc Terrtry	(258)	0	(258)	0
	A	**Revenue - Power Sales**	**(258)**	-	**(258)**	-
		TOTAL OPERATING REVENUES	**87,241,551**	**63,528,462**	**62,979,026**	**8,488,238**
=(A)		*Memo: G/T/D Revenue*	*81,776,961*	*63,424,319*	*16,751,676*	*1,600,966*
=(B)		*Memo: Other Affiliated Revenue*	*5,446,623*	*78,632*	*46,227,185*	*6,894,981*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Non*	*17,967*	*25,511*	*165*	*(7,709)*
		Memo: Total Operating Revenues	*87,241,551*	*63,528,462*	*62,979,026*	*8,488,238*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***5,446,623***	***78,632***	***46,227,185***	***6,894,981***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***81,794,928***	***63,449,831***	***16,751,841***	***1,593,257***
		Memo: Total Operating Revenues	***87,241,551***	***63,528,462***	***62,979,026***	***8,488,238***
		FUEL EXPENSES				
5010000		Fuel	(16,846)	0	(16,846)	0
5010001		Fuel Consumed	28,827,383	0	28,827,383	0
5010003		Fuel - Procure Unload & Handle	1,344,632	0	1,344,632	0
5010019		Fuel Oil Consumed	1,080,903	0	1,080,903	0
5010027		Gypsum handling/disposal costs	15,357	0	15,357	0
5010028		Gypsum Sales Proceeds	(102,328)	0	(102,328)	0
		Fuel Expense Total	**31,149,101**	-	**31,149,101**	-
5010005		Fuel - Deferred	(2,706,347)	0	(2,706,347)	0
		Deferred Fuel Expense	**(2,706,347)**	-	**(2,706,347)**	-
		Over Under Fuel Expense				
		Fuel for Electric Generation	**28,442,754**	-	**28,442,754**	-
5010029		Gypsum handling/displ-Affiliat	1,286	0	1,286	0
		Fuel from Affiliates for Electric Generation	**1,286**	-	**1,286**	-
5090000		Allow Consum Title IV SO2	844,368	0	844,368	0
5090005		An. NOx Cons. Exp	13,856	0	13,856	0
		Allowances - Consumption	**858,223**	-	**858,223**	-
5020002		Urea Expense	559,304	0	559,304	0
5020003		Trona Expense	26,189	0	26,189	0
5020004		Limestone Expense	340,846	0	340,846	0
5020005		Polymer expense	895	0	895	0
5020007		Lime Hydrate Expense	1,452	0	1,452	0
		Emissions Control - Chemicals	**928,686**	-	**928,686**	-
		Total Fuel for Electric Generation	**30,230,950**	-	**30,230,950**	-
		Memo: NonAff Fuel/Allow/Emissions	***30,229,663***	-	***30,229,663***	-
5550004		Purchased Power-Pool Capacity	181,949	0	181,949	0
5550005		Purchased Power - Pool Energy	676,093	0	676,093	0
5550027		Purch Pwr-Non-Fuel Portion-Aff	3,776,813	0	3,776,813	0
5550029		Purch Power-Assoc-Tinsfr Price	0	43,994,390	0	0
5550046		Purch Power-Fuel Portion-Affil	6,649,126	0	6,649,126	0
5550101		Purch Power-Pool Non-Fuel - Aff	168,508	0	168,508	0
5550102		Pur Power-Pool NonFuel-OSS-Aff	103,888	0	103,888	0
		Purchased Electricity from AEP - Affiliates	**11,556,377**	**43,994,390**	**11,556,377**	-
5550001		Purch Pwr-NonTrading-Nonassoc	99,503	0	99,503	0
5550032		Gas-Conversion-Mone Plant	106,336	0	106,336	0
5550039		PJM Inadvertent Mtr Res-OSS	2,783	0	2,783	0
5550040		PJM Inadvertent Mtr Res-LSE	682	0	682	0
5550041		PJM Ancillary Serv - Sync	590	0	590	0
5550074		PJM Reactive-Charge	162,064	0	162,064	0
5550075		PJM Reactive-Credit	(213,930)	0	(213,930)	0
5550076		PJM Black Start-Charge	112,608	0	112,608	0
5550077		PJM Black Start-Credit	(7)	0	(7)	0
5550078		PJM Regulation-Charge	436,851	0	436,851	0
5550079		PJM Regulation-Credit	(192,863)	0	(192,863)	0
5550083		PJM Spinning Reserve-Charge	824,159	0	824,159	0
5550084		PJM Spinning Reserve-Credit	(250,609)	0	(250,609)	0

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		Kentucky Power Int Consol GLS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
09B V2009-01-01	Layout: GLS8016 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	YTD Jan 2014	YTD Jan 2014	YTD Jan 2014	YTD Jan 2014
5550090	PJM 30m Suppl Rserv Charge LSE	383,563	0	383,563	0
5550099	PJM Purchases non-ECR-Auction	503,549	0	503,549	0
5550100	Capacity Purchases-Auction	7,129	0	7,129	0
5550107	Capacity purchases - Trading	9,206	0	9,206	0
	Purchased Electricity for Resale - NonAffiliated	**1,991,614**	-	**1,991,614**	-
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	**13,547,991**	**43,994,390**	**13,547,991**	-
	GROSS MARGIN	**43,462,611**	**19,534,073**	**19,200,085**	**8,488,238**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	295,384	0	295,384	0
5020000	Steam Expenses	248,023	0	248,023	0
5050000	Electric Expenses	37,729	0	37,729	0
5060000	Misc Steam Power Expenses	498,223	0	498,223	0
5060002	Misc Steam Power Exp-Assoc	5,502	0	5,502	0
5060003	Removal Cost Expense - Steam	0	0	0	0
5060004	NSR Settlement Expense	(1,427)	0	(1,427)	0
5060025	Misc Stm Pwr Exp Environmental	64	0	64	0
	Steam Generation Op Exp	**1,083,497**	-	**1,083,497**	-
	Nuclear Generation Op Exp	-	-	-	-
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	43,717	7	43,551	158
5570000	Other Expenses	164,228	1,137	162,847	244
5570007	Other Pwr Exp - Wholesale RECs	1,241	1,241	0	0
5757000	PJM Admin-MAM&SC- OSS	51,361	0	51,361	0
5757001	PJM Admin-MAM&SC- Internal	83,985	0	83,985	0
	Other Generation Op Exp	**344,630**	**2,385**	**341,743**	**402**
5600000	Oper Supervision & Engineering	78,660	165	485	78,010
5611000	Load Dispatch - Reliability	1,299	0	0	1,299
5612000	Load Dispatch-Mntr&Op TransSys	67,339	0	0	67,339
5614000	PJM Admin-SSC&DS-OSS	50,600	0	50,600	0
5614001	PJM Admin-SSC&DS-Internal	83,056	0	83,056	0
5615000	Reliability Plng&Stds Develop	6,109	544	568	4,996
5618000	PJM Admin-RP&SDS-OSS	19,093	0	19,093	0
5618001	PJM Admin-RP&SDS- Internal	28,482	0	28,482	0
5620001	Station Expenses - Nonassoc	23,692	0	0	23,692
5630000	Overhead Line Expenses	17,114	0	0	17,114
5650002	Transmssn Elec by Others-NAC	24,526	0	24,526	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	3,707,100	0	0
5650012	PJM Trans Enhancement Charge	334,874	0	334,874	0
5650015	PJM TO Serv Exp - Aff	7,485	0	7,485	0
5650016	PJM NITS Expense - Affiliated	319,966	0	319,966	0
5650019	Affil PJM Trans Enhncement Exp	16,071	0	16,071	0
5650020	PROVISION PJM NITS Aff Expens	(30,740)	0	(30,740)	0
5660000	Misc Transmission Expenses	68,918	1,272	1,391	66,255
5670002	Rents - Associated	0	0	0	52,685
	Transmission Op Exp	**1,116,545**	**3,709,081**	**855,857**	**311,391**
5800000	Oper Supervision & Engineering	63,212	62,574	470	168
5810000	Load Dispatching	816	171	0	644
5820000	Station Expenses	10,122	7,066	0	3,056
5830000	Overhead Line Expenses	71,005	71,005	0	0
5840000	Underground Line Expenses	4,859	4,859	0	0
5850000	Street Lighting & Signal Sys E	7,571	7,571	0	0
5860000	Meter Expenses	55,843	55,770	(4)	77
5870000	Customer Installations Exp	14,161	14,161	0	0
5880000	Miscellaneous Distribution Exp	324,162	321,617	335	2,210
5890001	Rents - Nonassociated	112,105	112,105	0	0
5890002	Rents - Associated	6,652	6,652	0	0
	Distribution Op Exp	**670,508**	**663,552**	**801**	**6,155**
9010000	Supervision - Customer Accts	22,747	22,747	0	0
9020000	Meter Reading Expenses	3,810	3,774	27	10
9020002	Meter Reading - Regular	32,258	32,258	0	0
9020003	Meter Reading - Large Power	3,876	3,876	0	0
9020004	Read-in & Read-Out Meters	5,391	5,391	0	0
9030000	Cust Records & Collection Exp	27,314	26,465	321	528
9030001	Customer Orders & Inquiries	175,616	175,475	141	0
9030002	Manual Billing	2,969	2,886	0	83

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9030003	Postage - Customer Bills	57,687	57,687	0	0
9030004	Cashiering	7,842	7,171	333	337
9030005	Collection Agents Fees & Exp	127	127	0	0
9030006	Credit & Oth Collection Activ	56,208	56,208	0	0
9030007	Collectors	44,810	44,810	0	0
9030009	Data Processing	14,824	14,824	0	0
9040007	Uncoll Accts - Misc Receivable	(2,408)	(2,408)	0	0
9050000	Misc Customer Accounts Exp	1,277	1,277	0	0
9070000	Supervision - Customer Service	9,760	9,765	(3)	(2)
9070001	Supervision - DSM	22	9	7	7
9080000	Customer Assistance Expenses	41,570	41,501	35	33
9080009	Cust Assistance Expense - DSM	554,811	554,796	8	7
9090000	Information & Instruct Advrts	299	89	154	56
9100000	Misc Cust Svc&Informational Ex	207	66	90	51
	Customer Service and Information Op Exp	**1,061,017**	**1,058,794**	**1,113**	**1,110**
9120000	Demonstrating & Selling Exp	1,001	1,001	0	0
9120003	Demo & Selling Exp - Area Dev	(323)	(323)	0	0
	Sales Expenses	**678**	**678**	-	-
	Memo: Insurance (9240 9250)	**782,094**	**38,737**	**723,794**	**19,563**
9200000	Administrative & Gen Salaries	691,147	314,143	264,252	112,752
9210001	Off Supl & Exp - Nonassociated	154,640	93,429	40,538	20,673
9220000	Administrative Exp Trnsf - CI	(56,424)	(56,424)	0	0
9220001	Admin Exp Trnsf to Cnstrction	(38,005)	(38,005)	0	0
9230001	Outside Svcs Empl - Nonassoc	97,473	49,783	30,661	17,030
9230003	AEPSC Billed to Client Co	126,998	54,240	31,586	41,172
9240000	Property Insurance	39,256	13,827	9,239	16,190
9250000	Injuries and Damages	101,985	69,093	28,654	4,238
9250001	Safety Dinners and Awards	165	128	33	4
9250002	Emp Accdent Prvntion-Adm Exp	788	679	73	36
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	653,990	(32,418)	686,978	(569)
9250007	Prsnal Injries&Prop Dmage-Pub	93	40	22	31
9250010	Frg Ben Loading - Workers Comp	(14,183)	(12,611)	(1,205)	(367)
9260000	Employee Pensions & Benefits	382	382	0	0
9260001	Edit & Print Empl Pub-Salaries	975	357	381	237
9260002	Pension & Group Ins Admin	4,794	3,088	1,381	325
9260003	Pension Plan	338,810	184,806	131,346	22,658
9260004	Group Life Insurance Premiums	11,803	5,287	5,595	921
9260005	Group Medical Ins Premiums	342,066	234,049	65,645	42,373
9260007	Group L-T Disability Ins Prem	964	698	143	123
9260009	Group Dental Insurance Prem	16,716	12,095	2,725	1,896
9260010	Training Administration Exp	33	16	16	2
9260012	Employee Activities	53	(23)	1	75
9260014	Educational Assistance Pmts	450	450	0	0
9260021	Postretirement Benefits - OPEB	(271,557)	(144,801)	(106,497)	(20,260)
9260027	Savings Plan Contributions	144,294	66,947	70,150	7,197
9260037	Supplemental Pension	252	252	0	0
9260040	SFAS 112 Postemployment Benef	1,818	0	1,818	0
9260050	Frg Ben Loading - Pension	(66,909)	(53,556)	(10,501)	(2,851)
9260051	Frg Ben Loading - Grp Ins	(97,584)	(79,744)	(12,422)	(5,418)
9260052	Frg Ben Loading - Savings	(40,875)	(26,569)	(11,998)	(2,309)
9260053	Frg Ben Loading - OPEB	25,550	19,802	4,168	1,581
9260055	IntercoFringeOffset- Don't Use	(95,077)	(23,556)	(63,237)	(8,284)
9260057	Postret Ben Medicare Subsidy	43,209	21,254	19,570	2,385
9260058	Frg Ben Loading - Accrual	(73,183)	(53,867)	(18,259)	(1,057)
9260060	Amort-Post Retirement Benefit	18,052	10,798	5,934	1,319
9270000	Franchise Requirements	11,823	11,823	0	0
9280000	Regulatory Commission Exp	(98)	(10)	(81)	(7)
9280002	Regulatory Commission Exp-Case	1,421	579	411	430
9301002	Radio Station Advertising Time	5	2	2	1
9301010	Publicity	144	51	61	32
9301012	Public Opinion Surveys	110	110	0	0
9301015	Other Corporate Comm Exp	2,180	1,977	134	69
9302000	Misc General Expenses	60,785	21,424	24,348	15,013
9302003	Corporate & Fiscal Expenses	1,059	1,670	(409)	(202)
9302004	Research, Develop&Demonstr Exp	274	274	0	0
9302458	AEPSC Non Affiliated expenses	0	0	0	0
9310001	Rents - Real Property	7,635	7,635	0	0
9310002	Rents - Personal Property	16,584	9,598	6,017	969

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09B V2009-01-01 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

		Kentucky Power Int Consol GLS8016 Actual YTD Jan 2014	Kentucky Power Company - Distribution 110 Actual YTD Jan 2014	Kentucky Power Company - Generation 117 Actual YTD Jan 2014	Kentucky Power Company - Transmission 180 Actual YTD Jan 2014
	Administration & General	**2,164,880**	**689,201**	**1,207,271**	**268,408**
4111005	Accretion Expense	79,484	0	79,484	0
	Accretion	**79,484**	-	**79,484**	-
4116000	Gain From Disposition of Plant	(335)	(335)	0	0
	Loss/(Gain) on Utility Plant	**(335)**	**(335)**	-	-
9302006	Assoc Bus Dev - Materials Sold	2,500	2,500	0	0
9302007	Assoc Business Development Exp	3,806	1,029	47	2,729
	Associated Business Development Expenses	**6,305**	**3,529**	**47**	**2,729**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4265009	Factored Cust A/R Exp - Affil	73,240	73,240	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	197,134	197,134	0	0
	Opr Exp and Factored A/R	**270,373**	**270,373**	-	-
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	4,410	1,552	1,884	974
	Expense of Non-Utility Operation	**4,410**	**1,552**	**1,884**	**974**
4210009	Misc Non-Op Exp - NonAssoc	846	162	577	107
	Misc NonOp Expenses - NonAssoc	**846**	**162**	**577**	**107**
4261000	Donations	74,446	23,065	47,865	3,516
	Donation Contributions	**74,446**	**23,065**	**47,865**	**3,516**
	Provision for Penalties	-	-	-	-
4264000	Civic & Political Activities	27,971	10,455	11,178	6,339
	Civic & Political Activities	**27,971**	**10,455**	**11,178**	**6,339**
4265002	Other Deductions - Nonassoc	27	2	23	1
4265033	Ohio Merger - Transition Costs	3,927	0	3,927	0
	Other Deductions	**3,954**	**2**	**3,950**	**1**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**382,001**	**305,610**	**65,454**	**10,937**
	Operational Expenses	**6,909,110**	**6,432,496**	**3,635,266**	**601,133**
5100000	Maint Supv & Engineering	329,296	0	329,296	0
5110000	Maintenance of Structures	164,552	0	164,552	0
5120000	Maintenance of Boiler Plant	785,487	0	785,487	0
5130000	Maintenance of Electric Plant	292,727	0	292,727	0
5140000	Maintenance of Misc Steam Plt	155,820	0	155,820	0
	Steam Generation Maintenance	**1,727,882**	-	**1,727,882**	-
	Nuclear Generation Maintenance	-	-	-	-
	Hydro Generation Maintenance	-	-	-	-
	Other Generation Maintenance	-	-	-	-
5680000	Maint Supv & Engineering	5,921	0	6	5,915
5690000	Maintenance of Structures	36	0	0	36
5691000	Maint of Computer Hardware	2,259	27	21	2,212
5692000	Maint of Computer Software	35,494	262	0	35,232
5693000	Maint of Communication Equip	3,047	0	0	3,047
5700000	Maint of Station Equipment	104,939	8,746	0	96,193
5710000	Maintenance of Overhead Lines	133,008	1,663	0	131,345
5720000	Maint of Underground Lines	108	0	0	108
5730000	Maint of Misc Trnsmssion Plt	54,700	0	0	54,700
	Transmission Maintenance	**339,511**	**10,699**	**27**	**328,786**
5900000	Maint Supv & Engineering	399	374	1	24
5910000	Maintenance of Structures	391	347	0	44
5920000	Maint of Station Equipment	21,087	15,310	46	5,732
5930000	Maintenance of Overhead Lines	2,084,085	2,083,933	3	149
5930001	Tree and Brush Control	29,863	29,863	0	0
5930010	Storm Expense Amortization	391,537	391,537	0	0
5940000	Maint of Underground Lines	12,734	12,734	0	0
5950000	Maint of Lne Trnf Rglators&Dvi	6,598	6,598	0	0
5960000	Maint of Strt Lghtng & Signal S	8,155	8,155	0	0
5970000	Maintenance of Meters	8,860	8,020	0	840
5980000	Maint of Misc Distribution Plt	15,399	15,322	0	77
	Distribution Maintenance	**2,579,108**	**2,572,193**	**50**	**6,865**
9350001	Maint of Structures - Owned	17,394	18,198	(441)	(363)
9350002	Maint of Structures - Leased	4,702	4,702	(0)	(0)
9350003	Maint of Prpty Held Fture Use	0	0	0	0
9350013	Maint of Cmmncation Eq-Unall	40,288	36,590	3,698	0
9350015	Maint of Office Furniture & Eq	106,032	71,373	34,659	0
9350018	Maint of Gen Plant-SCADA Equ	15	14	1	0

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098 V2009-01-01 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

		Kentucky Power Int Consol GLS8016 Actual YTD Jan 2014	Kentucky Power Company - Distribution 110 Actual YTD Jan 2014	Kentucky Power Company - Generation 117 Actual YTD Jan 2014	Kentucky Power Company - Transmission 180 Actual YTD Jan 2014
9350024	Maint of DA-AMI Comm Equip	8	8	0	0
	Administration & General Maintenance	**168,439**	**130,885**	**37,917**	**(363)**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**4,814,940**	**2,713,777**	**1,765,876**	**335,287**
	Total Operational and Maintenance Expenses	**11,724,050**	**9,146,274**	**5,401,142**	**936,420**
4040001	Amort. of Plant	275,768	122,106	107,234	46,428
4060001	Amort of Plt Acq Adj	3,218	0	0	3,218
	DDA Amortization	**278,986**	**122,106**	**107,234**	**49,646**
4073000	Regulatory Debits	24,091	0	0	24,091
	DDA Regulatory Debits	**24,091**	-	-	**24,091**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**303,077**	**122,106**	**107,234**	**73,737**
4030001	Depreciation Exp	7,356,651	2,089,958	4,557,162	709,532
	DDA Depreciation	**7,356,651**	**2,089,958**	**4,557,162**	**709,532**
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	134,664	0	134,664	0
	DDA Asset Retirement Obligation	**134,664**	-	**134,664**	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**7,491,315**	**2,089,958**	**4,691,826**	**709,532**
	Depreciation and Amortization	**7,794,391**	**2,212,063**	**4,799,059**	**783,269**
	Franchise Taxes	-	-	-	-
408100614	State Gross Receipts Tax	5,000	0	5,000	0
	Revenue-kWhr Taxes	**5,000**	-	**5,000**	-
4081002	FICA	366,271	149,527	201,494	15,249
4081003	Federal Unemployment Tax	15,975	7,037	8,136	802
4081007	State Unemployment Tax	48,335	15,661	30,844	1,830
4081033	Fringe Benefit Loading - FICA	(74,832)	(48,615)	(21,883)	(4,334)
4081034	Fringe Benefit Loading - FUT	(409)	(322)	(61)	(26)
4081035	Fringe Benefit Loading - SUT	(873)	(698)	(123)	(52)
	Payroll Taxes	**354,466**	**122,590**	**218,407**	**13,469**
408102014	State Business Occup Taxes	331,048	0	331,048	0
	Capacity Taxes	**331,048**	-	**331,048**	-
408100512	Real Personal Property Taxes	238,333	0	238,333	0
408100513	Real Personal Property Taxes	852,770	499,437	75,343	277,990
408102914	Real-Pers Prop Tax-Cap Leases	1,791	1,352	104	335
408103614	Real Prop Tax-Cap Leases	2,125	2,125	0	0
408200513	Real Personal Property Taxes	4,717	806	0	3,911
	Property Taxes	**1,099,736**	**503,720**	**313,780**	**282,236**
408101813	St Publ Serv Comm Tax-Fees	78,854	78,854	0	0
	Regulatory Fees	**78,854**	**78,854**	-	-
	Production Taxes	-	-	-	-
408101913	State Sales and Use Taxes	1,295	1,295	0	0
	Miscellaneous Taxes	**1,295**	**1,295**	-	-
	Other Non-Income Taxes	**1,295**	**1,295**	-	-
	Taxes Other Than Income Taxes	**1,870,399**	**706,459**	**868,235**	**295,705**
	TOTAL OPERATING EXPENSES	**21,388,841**	**12,064,796**	**11,068,436**	**2,015,394**
	Memo: SEC Total Operating Expenses	**65,167,781**	**56,059,186**	**54,847,376**	**2,015,394**
	OPERATING INCOME	**22,073,771**	**7,469,277**	**8,131,650**	**6,472,844**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	1,788	1,788	0	0
	Interest & Dividend NonAffiliated	**1,788**	**1,788**	-	-
4190001	Interest Inc - Assoc Non CBP	1,039	1,039	0	0
4190005	Interest Income - Assoc CBP	51	359	(2,305)	1,998
	Interest & Dividend Affiliated	**1,090**	**1,397**	**(2,305)**	**1,998**
	Total Interest & Dividend Income	**2,878**	**3,185**	**(2,305)**	**1,998**
4210039	Carrying Charges	5,608	0	0	5,608
	Interest & Dividend Carrying Charge	**5,608**	-	-	**5,608**
	Memo: Total Interest & Dividend Income w/ Carrying	**8,486**	**3,185**	**(2,305)**	**7,606**
4191000	Allw Oth Fnds Usd Dring Cnstr	432,339	37,525	281,335	113,480
	AFUDC	**432,339**	**37,525**	**281,335**	**113,480**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
	Interest LTD IPC	-	-	-	-

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jan 2014
02/11/2014 11:39

DSB V2099-01-01	Layout: GLS8016 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Jan 2014	Kentucky Power Company - Distribution 110 Actual YTD Jan 2014	Kentucky Power Company - Generation 117 Actual YTD Jan 2014	Kentucky Power Company - Transmission 180 Actual YTD Jan 2014
4300001	Interest Exp - Assoc Non-CBP	87,500	34,780	25,741	26,979
	Interest LTD Notes Payable - Affiliated	**87,500**	**34,780**	**25,741**	**26,979**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	2,833,226	1,126,179	833,478	873,568
	Interest LTD Senior Unsecured	**2,833,226**	**1,126,179**	**833,478**	**873,568**
4270012	PCRB Interest Exp-Assoc	1,039	1,039	0	0
	Interest LTD Other - Affil	**1,039**	**1,039**	-	-
4270005	Int on LTD - Other LTD	255,556	255,556	0	0
	Interest LTD Other - NonAffil	**255,556**	**255,556**	-	-
	Interest on Long-Term Debt	**3,177,320**	**1,417,554**	**859,219**	**900,547**
4300003	Int to Assoc Co - CBP	2,299	(219)	32,059	(29,541)
	Interest STD - Affil	**2,299**	**(219)**	**32,059**	**(29,541)**
4310007	Lines Of Credit	47,268	25,525	15,586	6,157
	Interest STD - NonAffil	**47,268**	**25,525**	**15,586**	**6,157**
	Interest on Short Term Debt	**49,567**	**25,306**	**47,644**	**(23,384)**
4260006	Amrtz Dscnt&Exp-Sn Unsec Note	39,266	15,608	11,551	12,107
	Amort of Debt Disc. Prem & Exp	**39,266**	**15,608**	**11,551**	**12,107**
4281004	Amrtz Loss Rcqured Debt-Dbnt	2,804	1,183	714	907
	Amort Loss on Reacquired Debt	**2,804**	**1,183**	**714**	**907**
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	776	0	23	753
4310002	Interest on Customer Deposits	1,853	1,853	0	0
	Other Interest - NonAffil	**2,629**	**1,853**	**23**	**753**
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(309,070)	(26,796)	(200,935)	(81,339)
	AFUDC-Borrowed Funds	**(309,070)**	**(26,796)**	**(200,935)**	**(81,339)**
	Total Interest Charges	**2,962,515**	**1,434,708**	**718,216**	**809,591**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**19,552,080**	**6,075,278**	**7,692,464**	**5,784,338**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes UOI - Federal	6,220,981	2,294,691	2,282,302	1,643,987
4092001	Inc Tax Oth Inc&Ded-Federal	(72,633)	(37,162)	(28,065)	(7,407)
	Federal Current Income Tax	**6,148,347**	**2,257,529**	**2,254,238**	**1,636,581**
4101001	Prov Def I/T Utl Op Inc-Fed	3,709,425	196,674	3,236,048	276,704
4102001	Prov Def I/T Oth I&D - Federal	44,571	31,271	7,452	5,849
4111001	Prv Def I/T-Cr Utl Op Inc-Fed	(3,884,690)	(673,168)	(3,102,166)	(109,356)
	Federal Deferred Income Tax	**(130,693)**	**(445,223)**	**141,333**	**173,197**
4114001	ITC Adj. Utility Oper - Fed	(8,003)	(1,260)	(1,926)	(4,817)
	Federal Investment Tax Credits	**(8,003)**	**(1,260)**	**(1,926)**	**(4,817)**
	Federal Income Taxes	**6,009,651**	**1,811,046**	**2,393,644**	**1,804,960**
409100214	Income Taxes UOI - State	1,198,246	415,311	473,013	309,922
409200214	Inc Tax Oth Inc Ded - State	(12,607)	(6,450)	(4,871)	(1,286)
	State Current Income Tax	**1,185,639**	**408,861**	**468,142**	**308,637**
4111002	Prv Def I/T-Cr UtlOpInc-State	(50,960)	0	(50,960)	0
	State Deferred Income Tax	**(50,960)**	-	**(50,960)**	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	**1,134,679**	**408,861**	**417,182**	**308,637**
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	**7,144,330**	**2,219,907**	**2,810,826**	**2,113,597**
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**12,407,750**	**3,855,371**	**4,881,638**	**3,670,741**
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	**12,407,750**	**3,855,371**	**4,881,638**	**3,670,741**

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Jan 2014
02/11/2014 18:19

Layout : GLS8216

09B V2099-01- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Jan 2014	Kentucky Power Company - 110 YTD Jan 2014	Kentucky Power Company - Generation 117 YTD Jan 2014	Kentucky Power Company - 180 YTD Jan 2014
ASSETS				
Cash and Cash Equivalents	883,036	883,036	0	0
Other Cash Deposits	0	0	0	0
Customers	16,864,417	8,845,745	7,129,769	888,902
Accrued Unbilled Revenues	195,496	195,496	0	0
Miscellaneous Accounts Receivable	43,497,323	4,004,732	100,273,208	9,671,200
Allowances for Uncollectible Accounts	(82,057)	(75,154)	(6,903)	0
Accounts Receivable	60,475,179	12,970,819	107,396,074	10,560,103
Advances to Affiliates	26,289,945	23,626,948	(127,593,998)	130,256,995
Fuel, Materials and Supplies	108,991,465	2,259,567	105,836,201	895,697
Risk Management Contracts - Current	3,075,649	99	3,075,550	0
Margin Deposits	2,066,466	17,137	2,049,329	0
Unrecovered Fuel - Current	0	0	0	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	3,694,971	3,057,997	519,779	117,194
TOTAL CURRENT ASSETS	205,476,710	42,815,603	91,282,934	141,829,990
Electric Production	1,472,664,140	738,841,811	1,490,862,538	505,334,666
Electric Transmission	510,318,011	0	0	0
Electric Distribution	695,095,133	0	0	0
General Property, Plant and Equipment	62,490,966	199,571	4,169,386	1,160,479
Construction Work-In-Progress	130,707,958	13,334,563	81,211,438	36,161,957
TOTAL PROPERTY, PLANT and EQUIPMENT	2,871,276,209	752,375,745	1,576,243,363	542,657,101
less: Accumulated Depreciation and Amortization	(948,747,408)	(232,401,441)	(549,822,201)	(166,523,766)
NET PROPERTY, PLANT and EQUIPMENT	1,922,528,800	519,974,303	1,026,421,162	376,133,335
Net Regulatory Assets	216,191,652	103,939,808	56,715,085	55,536,758
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	2,982,489	0	2,982,489	0
Employee Benefits and Pension Assets	13,956,540	5,252,260	8,110,818	593,462
Other Non Current Assets	18,612,594	7,091,591	7,838,156	3,682,847
TOTAL OTHER NON-CURRENT ASSETS	251,743,275	116,283,660	75,646,548	59,813,067
TOTAL ASSETS	2,379,748,786	679,073,566	1,193,350,644	577,776,393
LIABILITIES				
Accounts Payable	86,698,464	76,186,810	77,464,956	3,498,514
Advances from Affiliates	0	0	0	0
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	0	0	0	0
Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
Risk Management Liabilities	779,698	955	778,743	0
Accrued Taxes	19,714,384	8,570,127	2,273,527	8,870,730
Memo: Property Taxes	15,999,752	6,811,516	5,356,657	3,831,579
Accrued Interest	9,624,840	3,848,610	2,858,283	2,917,946
Risk Management Collateral	703,940	0	703,940	0
Utility Customer Deposits	24,354,039	24,354,039	0	0
Deposits - Customer and Collateral	25,057,979	24,354,039	703,940	0
Over-Recovered Fuel Costs - Current	144,291	0	144,291	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	930,167	454,453	371,682	104,032
Tax Collections Payable	2,632,903	2,512,445	115,558	4,900
Revenue Refunds - Accrued	1,378,946	0	259,350	1,119,596

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Jan 2014
02/11/2014 10:19

Layout : GLS8216

09B V2099-01-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Jan 2014	Kentucky Power Company - 110 YTD Jan 2014	Kentucky Power Company - Generation 117 YTD Jan 2014	Kentucky Power Company - 180 YTD Jan 2014
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,729,439	653,751	997,873	77,815
	Accrued Rents	(1,549)	(1,549)	0	0
	Accrued ICP	3,769,133	2,193,152	1,172,992	402,989
	Accrued Vacations	5,260,357	2,062,442	2,966,547	231,368
	Misc Employee Benefits	987,726	420,134	566,435	1,156
	Payroll Deductions	223,014	99,600	109,056	14,358
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	849,128	437,274	372,323	39,531
2530022	Customer Advance Receipts	1,335,132	1,335,132	0	0
	Customer Advance	1,335,132	1,335,132	0	0
	Control Cash Disbursement Account	722,131	722,131	0	0
	JMG Liability	0	0	0	0
2420087	Engage to Gain Incentive	421,265	273,097	102,833	45,335
2420088	Econ. Development Fund Curr	233,000	0	233,000	0
2420512	Unclaimed Funds	4,133	4,133	0	0
2420542	Acc Cash Franchise Req	72,199	72,199	0	0
242059214	Sales Use Tax - Lease Equip	18,293	18,134	84	75
2420643	Accrued Audit Fees	38,495	10,511	21,441	6,543
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	246,141	0	246,141	0
2530050	Deferred Rev -Pole Attachments	39,343	39,343	0	0
2530112	Other Deferred Credits-Curr	221,616	0	221,616	0
	Misc Current and Accrued Liabilities	1,848,811	417,416	1,379,441	51,953
	Current Other and Accrued Liabilities	20,735,169	10,851,927	7,939,576	1,943,666
	Other Current Liabilities	**21,665,336**	**11,306,380**	**8,311,257**	**2,047,698**
	TOTAL CURRENT LIABILITIES	**163,684,991**	**124,266,921**	**92,534,998**	**17,334,888**
	Long-Term Debt - Affiliated	**20,000,000**	**7,949,800**	**5,883,600**	**6,166,600**
	Long-Term Debt - Non Affiliated	**730,000,000**	**210,669,700**	**355,915,400**	**163,414,900**
	Long-Term Debt - Premiums and Discounts Unamort	(597,431)	(237,473)	(175,752)	(184,206)
	Memo - LTD NonAffiliated and Premiums	*729,402,569*	*210,432,227*	*355,739,648*	*163,230,694*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	2,107,464	0	2,107,464	0
	Long-Term Risk Management Liabilities - MTM	2,107,464	0	2,107,464	0
	Long-Term Risk Management Liabilities	**2,107,464**	**0**	**2,107,464**	**0**
	Deferred Income Taxes	**555,388,846**	**167,530,210**	**269,962,192**	**117,896,444**
	Deferred Investment Tax Credits	**117,744**	**22,905**	**35,902**	**58,937**
	Regulatory Liabilities and Deferred Credits	**23,380,686**	(30,470,047)	**60,268,822**	(6,418,089)
	Memo - Reg Liab and Def ITC	*23,498,430*	*(30,447,142)*	*60,304,723*	*(6,359,151)*
	Asset Retirement Obligation	**20,552,398**	**61,236**	**20,491,162**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,985,020**	**9,869,369**	(2,286,688)	**402,339**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Red	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	3,239,078	1,264,381	1,544,363	430,334
	Def Credits - Income Tax	679,196	360,765	275,890	42,541
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	111,772	111,772	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	6,998	0	6,998	0
2530067	IPP - System Upgrade Credits	269,595	0	0	269,595
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	156,390	156,390	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	102,044	0	0	102,044
	Def Credits - Other	535,028	156,390	6,998	371,639
	Total Other Deferred Credits	646,800	268,162	6,998	371,639

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Jan 2014
02/11/2014 18:19

Layout : GLS8216

09B V2099-01- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Jan 2014	Kentucky Power Company - 110 YTD Jan 2014	Kentucky Power Company - Generation 117 YTD Jan 2014	Kentucky Power Company - 180 YTD Jan 2014
Accumulated Provisions - Rate Refund	0	0	0	0
Accumulated Provisions - Misc	932,000	0	932,000	0
Other Non-Current Liabilities	**6,607,717**	**1,893,308**	**3,869,895**	**844,513**
TOTAL NON-CURRENT LIABILITIES	**1,365,542,443**	**367,289,008**	**716,071,996**	**282,181,439**
TOTAL LIABILITIES	**1,529,227,434**	**491,555,929**	**808,606,994**	**299,516,327**
Cumulative Pref Stocks of Subs - Not subject Mand Reder	**0**	**0**	**0**	**0**
Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
COMMON SHAREHOLDERS' EQUITY				
Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
Paid In Capital	**614,648,268**	**106,025,371**	**424,583,061**	**84,039,836**
Premium on Capital Stock	**0**	**0**	**0**	**0**
Retained Earnings	**192,098,674**	**59,168,496**	(43,598,460)	**176,528,639**
Accumulated Other Comprehensive Income (Loss)	(6,675,590)	(80,279)	(6,528,554)	(66,757)
TOTAL SHAREHOLDERS' EQUITY	**850,521,352**	**187,517,637**	**384,743,650**	**278,260,066**
Memo: Total Equity	850,521,352	187,517,637	384,743,650	278,260,066
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**2,379,748,786**	**679,073,566**	**1,193,350,644**	**577,776,393**

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Jan 2013
02/25/2014 08:58

Layout : GLS8216
09B V2099-01-(Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216 YTD Jan 2013	Kentucky Power Company - 110 YTD Jan 2013	Kentucky Power Company - Generation 117 YTD Jan 2013	Kentucky Power Company - 180 YTD Jan 2013
ASSETS				
Cash and Cash Equivalents	1,125,832	1,125,832	0	0
Other Cash Deposits	0	0	0	0
Customers	14,293,727	8,579,898	4,985,284	728,545
Accrued Unbilled Revenues	(25,425)	(25,425)	0	0
Miscellaneous Accounts Receivable	13,368,620	5,344,033	52,841,413	13,811,814
Allowances for Uncollectible Accounts	(9,818)	(9,818)	0	0
Accounts Receivable	27,627,105	13,888,689	57,826,697	14,540,359
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	88,266,015	2,093,477	85,373,351	799,187
Risk Management Contracts - Current	5,915,323	46,822	5,868,501	0
Margin Deposits	1,973,442	29,763	1,943,679	0
Unrecovered Fuel - Current	0	0	0	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	4,877,412	1,989,948	2,772,542	114,922
TOTAL CURRENT ASSETS	129,785,129	19,174,531	153,784,770	15,454,468
Electric Production	559,377,446	702,397,848	568,085,115	494,935,885
Electric Transmission	490,794,847	0	0	0
Electric Distribution	657,824,972	0	0	0
General Property, Plant and Equipment	63,121,088	199,571	4,370,046	1,129,887
Construction Work-in-Progress	42,007,064	14,444,685	2,282,769	25,279,610
TOTAL PROPERTY, PLANT and EQUIPMENT	1,813,125,416	717,042,104	574,737,930	521,345,382
less: Accumulated Depreciation and Amortization	(605,870,245)	(217,677,519)	(226,493,717)	(161,699,009)
NET PROPERTY, PLANT and EQUIPMENT	1,207,255,171	499,364,585	348,244,212	359,646,373
Net Regulatory Assets	213,330,616	122,552,992	34,769,218	56,008,406
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	6,207,854	0	6,207,854	0
Employee Benefits and Pension Assets	0	0	0	0
Other Non Current Assets	47,766,874	5,511,352	39,121,967	3,133,556
TOTAL OTHER NON-CURRENT ASSETS	267,305,344	128,064,344	80,099,038	59,141,962
TOTAL ASSETS	1,604,345,644	646,603,460	582,128,020	434,242,803
LIABILITIES				
Accounts Payable	53,658,537	65,114,337	42,897,439	4,275,400
Advances from Affiliates	16,278,255	(5,900,475)	132,113,233	(109,934,503)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	0	0	0	0
Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
Risk Management Liabilities	3,288,691	0	3,288,691	0
Accrued Taxes	8,028,810	4,515,708	(2,916,090)	6,429,192
Memo: Property Taxes	10,850,061	4,479,013	3,160,184	3,210,864
Accrued Interest	9,493,225	3,712,121	2,852,155	2,928,949
Risk Management Collateral	56,324	0	56,324	0
Utility Customer Deposits	23,607,021	23,607,021	0	0
Deposits - Customer and Collateral	23,663,345	23,607,021	56,324	0
Over-Recovered Fuel Costs - Current	6,037,388	0	6,037,388	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,327,597	866,790	241,380	219,427
Tax Collections Payable	1,929,680	1,903,001	19,376	7,302
Revenue Refunds - Accrued	3,704,841	1,635,430	14,573	2,054,838
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	920,505	570,656	251,868	97,981
Accrued Rents	(2,795)	(2,795)	0	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Jan 2013
02/25/2014 08:58

Layout : GLS8216

09B V2099-01 / Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS		Kentucky Power Int Consol GLS8216 YTD Jan 2013	Kentucky Power Company - 110 YTD Jan 2013	Kentucky Power Company - Generation 117 YTD Jan 2013	Kentucky Power Company - 180 YTD Jan 2013
	Accrued ICP	3,822,941	2,344,638	1,111,142	367,160
	Accrued Vacations	3,240,629	1,989,464	912,879	338,286
	Misc Employee Benefits	1,033,531	759,716	251,166	22,650
	Payroll Deductions	147,237	86,187	42,829	18,221
	Severance / SEI	463,981	258,527	85,039	120,415
	Accrued Workers Compensation	458,500	337,095	100,898	20,508
2530022	Customer Advance Receipts	2,060,661	2,060,661	0	0
	Customer Advance	2,060,661	2,060,661	0	0
	Control Cash Disbursement Account	1,753,628	1,753,628	0	0
	JMG Liability	0	0	0	0
2420512	Unclaimed Funds	3,657	3,657	0	0
2420542	Acc Cash Franchise Req	77,148	77,148	0	0
242059213	Sales Use Tax - Lease Equip	12,589	397	12,116	75
2420643	Accrued Audit Fees	30,027	13,135	8,934	7,958
2420656	Federal Mitigation Accru (NSR)	376,794	0	376,794	0
2420664	ST State Mitigation Def (NSR)	457,288	0	457,288	0
2530050	Deferred Rev -Pole Attachments	31,281	31,281	0	0
2530112	Other Deferred Credits-Curr	987,973	0	987,973	0
	Misc Current and Accrued Liabilities	1,976,756	125,617	1,843,105	8,033
	Current Other and Accrued Liabilities	21,510,094	13,821,824	4,632,875	3,055,394
	Other Current Liabilities	22,837,691	14,688,615	4,874,255	3,274,821
	TOTAL CURRENT LIABILITIES	143,285,942	105,737,328	189,203,395	(93,026,141)
	Long-Term Debt - Affiliated	20,000,000	6,907,200	7,335,600	5,757,200
	Long-Term Debt - Non Affiliated	530,000,000	197,753,600	176,839,800	155,406,600
	Long-Term Debt - Premiums and Discounts Unamort	(764,156)	(285,122)	(254,968)	(224,066)
	Memo - LTD NonAffiliated and Premiums	*529,235,844*	*197,468,478*	*176,584,832*	*155,182,534*
	Long-Term Risk Management Liabilities - Hedge	74,721	0	74,721	0
2440002	LT Unreal Losses - Non Affil	3,730,984	0	3,730,984	0
2440022	L/T Liability MTM Collateral	(517,133)	0	(517,133)	0
	Long-Term Risk Management Liabilities - MTM	3,213,851	0	3,213,851	0
	Long-Term Risk Management Liabilities	3,288,572	0	3,288,572	0
	Deferred Income Taxes	357,034,049	158,642,682	90,467,977	107,923,390
	Deferred Investment Tax Credits	336,591	59,685	84,672	192,234
	Regulatory Liabilities and Deferred Credits	25,649,112	(26,861,997)	57,509,058	(4,997,949)
	Memo - Reg Liab and Def ITC	*25,985,703*	*(26,802,312)*	*57,593,730*	*(4,805,715)*
	Asset Retirement Obligation	3,930,712	57,822	3,872,889	0
	Nuclear Decommissioning	0	0	0	0
	Employee Benefits and Pension Obligations	31,680,538	20,072,405	10,001,116	1,607,018
	Trust Preferred Securities	0	0	0	0
	Cumulative Preferred Stocks of Subs - Mandatory Rede	0	0	0	0
	Obligations Under Capital Leases	1,915,485	926,798	724,584	264,103
	Def Credits - Income Tax	1,287,290	370,877	876,869	39,545
2530114	Federl Mitigation Deferal(NSR)	754,942	0	754,942	0
	Def Credits - NSR	754,942	0	754,942	0
2520000	Customer Adv for Construction	59,408	59,408	0	0
	Customer Advances for Construction	59,408	59,408	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	261,009	0	0	261,009
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	162,146	162,146	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	115,600	0	0	115,600
	Def Credits - Other	538,754	162,146	0	376,608
	Total Other Deferred Credits	598,163	221,554	0	376,608
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	4,555,880	1,519,229	2,356,394	680,256
	TOTAL NON-CURRENT LIABILITIES	975,711,298	357,865,504	351,501,110	266,344,684
	TOTAL LIABILITIES	1,118,997,240	463,602,832	540,704,505	173,318,543
	Cumulative Pref Stocks of Subs - Not subject Mand Redem	0	0	0	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Jan 2013
02/25/2014 08.58

Layout : GLS8216
09B V2099-01-I Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216 YTD Jan 2013	Kentucky Power Company - 110 YTD Jan 2013	Kentucky Power Company - Generation 117 YTD Jan 2013	Kentucky Power Company - 180 YTD Jan 2013
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS' EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	238,750,000	106,025,371	48,684,793	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	196,509,410	54,631,786	(17,331,047)	159,208,670
Accumulated Other Comprehensive Income (Loss)	(361,006)	(60,578)	(217,834)	(82,593)
TOTAL SHAREHOLDERS' EQUITY	485,348,404	183,000,628	41,423,515	260,924,261
Memo: Total Equity	485,348,404	183,000,628	41,423,515	260,924,261
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	1,604,345,644	646,603,460	582,128,020	434,242,803

FINAL 02/12/2014

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - January, 2014

GLS7210Q

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	4,343,039.06	(1,583,436.15)	(9.12)	0.00	1,481,443,845.67
	TOTAL PRODUCTION	**1,478,684,251.88**	**4,343,039.06**	**(1,583,436.15)**	**(9.12)**	**0.00**	**1,481,443,845.67**
101/106	TRANSMISSION	503,165,571.80	1,492,309.80	(6,039.33)	0.00	0.00	504,651,842.27
101/106	DISTRIBUTION	733,776,590.81	2,914,857.05	(912,170.22)	0.00	0.00	735,779,277.64
	TOTAL (ACCOUNTS 101 & 106)	**2,715,626,414.49**	**8,750,205.91**	**(2,501,645.70)**	**(9.12)**	**0.00**	**2,721,874,965.58**
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	(521,258.91)	0.00	5,757,890.26
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**2,721,905,563.66**	**8,750,205.91**	**(2,501,645.70)**	**(521,268.03)**	**0.00**	**2,727,632,855.84**
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		10,859,016.03				
107000X	TRANSFERS		(8,750,205.91)				
107000X	END. BAL.		2,108,810.12				130,707,958.31
	TOTAL ELECTRIC UTILITY PLANT	**2,857,910,670.58**	**10,859,016.03**	**(2,501,645.70)**	**(521,268.03)**	**0.00**	**2,865,746,772.88**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	**5,529,435.74**	**0.00**	**0.00**	**(0.03)**	**0.00**	**5,529,435.71**

Prepared by: PSnVision Report GLS7210Q
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - January, 2014

FINAL 02/11/2014

GLS7410Q — 02/10/14 16:32

Account	Description	BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	4,707,626.98	(1,583,436.15)	(100,263.61)	0.00	602,528,054.11
1080001/11	TRANSMISSION	161,537,795.16	709,531.91	(6,039.33)	(85,937.43)	0.00	162,155,350.31
1080001/11	DISTRIBUTION	192,744,660.64	2,090,426.87	(912,170.22)	(108,646.07)	0.00	193,814,271.22
1080013	PRODUCTION	(3,620,015.26)				(44,290.38)	(3,664,305.64)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698.85)	0.00	0.00	0.00	(761.38)	(27,460.23)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(121,112.80)	294,847.11	(8,146,518.21)
	TOTAL (108X accounts)	941,819,616.06	7,507,585.76	(2,501,645.70)	(415,959.91)	249,795.35	946,659,391.56
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	107,233.97			0.00	10,536,584.84
1110001	TRANSMISSION	1,607,792.68	46,428.49	0.00	0.00	0.00	1,654,221.17
1110001	DISTRIBUTION	7,182,584.75	122,105.76	0.00	0.00	0.00	7,304,690.51
	TOTAL (111X accounts)	19,219,728.30	275,768.22	0.00	0.00	0.00	19,495,496.52
1011006	CAPITAL LEASES	1,869,467.09	0.00	0.00	0.00	(280,821.82)	1,588,645.27
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	962,908,811.45	7,783,353.98	(2,501,645.70)	(415,959.91)	(31,026.47)	967,743,533.35
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	214,955.75	555.81	0.00	0.00	0.00	215,511.56
1240027	Other Property - RWIP	(3,400.00)	0.00	0.00	0.00	0.00	(3,400.00)
1240028	Other Property - RETIRE	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL NONUTILITY PLANT	211,555.75	555.81	0.00	0.00	0.00	212,111.56

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

February 27, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed Form EIA-826, Monthly Electric Utility Sales and Revenue Report with State Distributions for the month of January 2014.

Sincerely,

Brian J Frantz

Brian J. Frantz
Manager –Regulated Accounting

BJF
Enclosure

U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue
Report with State Distributions – 2014

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**
Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650

Utility Name: Kentucky Power Company | **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan_X_ Feb__ Mar__ Apr__ May__ Jun__ Jul__ Aug__ Sep__ Oct__ Nov__ Dec__, 2014

Contact Person: Ronald F Davis | **Phone number: 614-716-3525**

Email: rfdavis@aep.com | **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 32,579	$ 14,401	$ 15,705		$ 62,685
	b. Megwatthours	338,050	140,625	248,421		727,096
	c. Number of consumers	140,271	30,792	1,300		172,363
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

March 27, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed February 2014 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-9	Income Statement
1-3	Details of Operating Revenues
4-7	Operating Expenses – Functional Expenses
8-9	Detail Statement of Taxes
Balance Sheet:	
10	Balance Sheet – Assets & Other Debits
10-12	Balance Sheet – Liabilities & Other Credits
11	Deferred Credits
12	Statement of Retained Earnings
Utility Property:	
13-14	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Brian J. Frantz
Manager –Regulated Accounting

BJF

Enclosure
Cc: Lila Munsey (w/pages)

American Electric Power

INCOME STATEMENT

GLS8016
YTD Feb 2014
03/10/2014 15:39

Layout: GLS8016
09B V2014-02-28 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

			Kentucky Power Int Consol GLS8016 Actual YTD Feb 2014	Kentucky Power Company - Distribution 110 Actual YTD Feb 2014	Kentucky Power Company - Generation 117 Actual YTD Feb 2014	Kentucky Power Company - Transmission 180 Actual YTD Feb 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	30,241,572	30,487,620	(246,048)	0
4400002		Residential Sales-W/O Space Ht	11,022,491	11,109,138	(86,647)	0
4400005		Residential Fuel Rev	17,018,471	17,018,471	0	0
	A	**Revenue - Residential Sales**	**58,282,534**	**58,615,229**	**(332,695)**	-
4420001		Commercial Sales	13,667,924	13,640,257	27,667	0
4420006		Sales to Pub Auth - Schools	2,504,103	2,498,573	5,530	0
4420007		Sales to Pub Auth - Ex Schools	2,482,490	2,475,248	7,242	0
4420013		Commercial Fuel Rev	6,891,160	6,891,160	0	0
	A	**Revenue - Commercial Sales**	**25,545,677**	**25,505,238**	**40,439**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	10,552,704	10,447,423	105,281	0
4420004		Ind Sales-NonAffil(Incl Mines)	4,984,498	4,952,031	32,467	0
4420016		Industrial Fuel Rev	13,059,135	13,059,135	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**28,596,337**	**28,458,589**	**137,749**	-
		Revenue - Industrial Sales	**28,596,337**	**28,458,589**	**137,749**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	238,376	235,456	2,921	0
4440002		Public St & Hwy Light Fuel Rev	57,541	57,541	0	0
	A	**Revenue - Other Retail Sales**	**295,918**	**292,997**	**2,921**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**112,720,466**	**112,872,053**	**(151,587)**	-
4560043		Oth Elec Rv-Trn-Aff-Trnf Pnce	0	0	0	6,630,454
4561033		PJM NITS Revenue - Affiliated	5,927,747	0	0	5,927,747
4561034		PJM TO Adm. Serv Rev - Aff	0	0	0	109,914
4561035		PJM Affiliated Trans NITS Cost	(5,910,528)	0	(5,910,528)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(109,914)	0
4561059		Affil PJM Trans Enhancmnt Rev	54,483	0	0	54,483
4561060		Affil PJM Trans Enhancmnt Cost	(54,329)	0	(54,329)	0
4561062		PROVISION PJM NITS Affil- Cost	(128,813)	0	(128,813)	0
4561063		PROVISION PJM NITS Affiliated	(37,856)	0	0	(37,856)
	B	**Revenue - Transmission-Affiliated**	**(149,296)**	-	**(6,203,584)**	**12,684,742**
4470150		Transm. Rev.-Dedic. Whls/Mun	9,285	0	(109,444)	118,729
4470206		PJM Trans loss credits-OSS	756,488	0	756,488	0
4470207		PJM transm loss charges - LSE	(7,356,139)	0	(7,356,139)	0
4470208		PJM Transm loss credits-LSE	1,273,044	0	1,273,044	0
4470209		PJM transm loss charges-OSS	(5,651,603)	0	(5,651,603)	0
4561002		RTO Formation Cost Recovery	5,776	0	(17,888)	23,664
4561003		PJM Expansion Cost Recov	16,901	0	(11,254)	28,155
4561005		PJM Point to Point Trans Svc	132,330	0	132,330	0
4561006		PJM Trans Owner Admin Rev	46,112	0	0	46,112
4561007		PJM Network Integ Trans Svc	2,336,735	0	0	2,336,735
4561019		Oth Elec Rev Trans Non Affil	13,439	0	0	13,439
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	787	0	0	787
4561029		PJM NITS Revenue Whsl Cus-NAff	439,048	0	0	439,048
4561030		PJM TO Serv Rev Whls Cus-NAff	7,044	0	0	7,044
4561058		NonAffil PJM Trans Enhncmt Rev	55,639	0	0	55,639
4561061		NAff PJM RTEP Rev for Whsl-FR	4,036	0	0	4,036
4561064		PROVISION PJM NITS WhslCus-NAf	(1,830)	0	0	(1,830)
4561065		PROVISION PJM NITS	(12,795)	0	0	(12,795)
	A	**Revenue - Transmission-NonAffiliated**	**(7,925,703)**	-	**(10,984,466)**	**3,058,763**
		Revenue - Transmission	**(8,074,998)**	-	**(17,188,050)**	**15,743,506**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	88,127	0	88,127	0
4470128		Sales for Res-Aff. Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,567,385**	-	**5,567,385**	-
4470002		Sales for Resale - NonAssoc	3,131	0	3,131	0
4470006		Sales for Resale-Bookout Sales	3,506,191	0	3,506,191	0
4470010		Sales for Resale-Bookout Purch	(5,353,498)	0	(5,353,498)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	594,298	0	594,298	0
4470028		Sale/Resale - NA - Fuel Rev	(8,069)	0	(8,069)	0
4470033		Whsal/Muni/Pub Auth Base Rev	524,474	0	524,474	0
4470066		PWR Trding Trans Exp-NonAssoc	(39)	0	(39)	0
4470081		Financial Spark Gas - Realized	5,418	0	5,418	0
4470082		Financial Electric Realized	1,823,691	0	1,823,691	0
4470089		PJM Energy Sales Margin	51,341,673	0	51,341,673	0

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			Kentucky Power Int Consol GLS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
			YTD Feb 2014	YTD Feb 2014	YTD Feb 2014	YTD Feb 2014
4470093		PJM Implicit Congestion-LSE	(14,071,327)	0	(14,071,327)	0
4470098		PJM Oper Reserve Rev-OSS	(1,675,231)	0	(1,675,231)	0
4470099		Capacity Cr Net Sales	88,662	0	88,662	0
4470100		PJM FTR Revenue-OSS	(5,482)	0	(5,482)	0
4470101		PJM FTR Revenue-LSE	5,100,901	0	5,100,901	0
4470103		PJM Energy Sales Cost	35,246,615	0	35,246,615	0
4470106		PJM Pt2Pt Trans Purch-NonAff	(27)	0	(27)	0
4470107		PJM NITS Purch-NonAff	5,374	0	5,374	0
4470109		PJM FTR Revenue-Spec	(67,670)	0	(67,670)	0
4470110		PJM TO Admin Exp -NonAff	(176)	0	(176)	0
4470115		PJM Meter Corrections-OSS	(10,220)	0	(10,220)	0
4470116		PJM Meter Corrections-LSE	50,448	0	50,448	0
4470124		PJM Incremental Spot-OSS	0	0	0	0
4470126		PJM Incremental Imp Cong-OSS	(15,814,370)	0	(15,814,370)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	(3,194)	0	(3,194)	0
4470144		Realiz Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim Margin Reclass	(175)	0	(175)	0
4470170		Non-ECR Auction Sales-OSS	620,404	0	620,404	0
4470174		PJM Whlse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	106,139	0	106,139	0
4470176		OSS Sharing Reclass-Reduction	(106,139)	0	(106,139)	0
4470180		Trading intra-book Reclass	(125,896)	0	(125,896)	0
4470181		Auction intra-book Reclass	125,896	0	125,896	0
4470202		PJM OpRes-LSE-Credit	355,360	0	355,360	0
4470203		PJM OpRes-LSE-Charge	(3,052,310)	0	(3,052,310)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,173	0	28,173	0
4470220		PJM Regulation - OSS	96,188	0	96,188	0
4470221		PJM Spinning Reserve - OSS	6,201	0	6,201	0
4470222		PJM Reactive - OSS	104,719	0	104,719	0
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	(9,835)	0	(9,835)	0
5550080		PJM Hourly Net Purch FERC	(10,124,508)	0	(10,124,508)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**49,307,406**	**-**	**49,307,406**	**-**
	A	**Revenue - Resale-Realized**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt MTM**	**-**	**-**	**-**	**-**
	A	**Revenue - Resale-Risk Mgmt Activities**	**-**	**-**	**-**	**-**
		Revenue - Sales for Resale	**54,874,791**	**-**	**54,874,791**	**-**
4470074		Sale for Resale-Aff Trnf Price	0	0	81,408,065	0
4540001		Rent From Elect Property - Af	51,894	157,264	0	0
	B	**Revenue - Other Ele-Affiliated**	**51,894**	**157,264**	**81,408,065**	**-**
4500000		Forfeited Discounts	825,901	825,901	0	0
4510001		Misc Service Rev - Nonaffil	39,994	37,735	0	2,259
4540002		Rent From Elect Property-NAC	1,300	300	0	1,000
4540005		Rent from Elec Prop-Pole Attch	978,752	978,752	0	0
4560007		Oth Elect Rev - DSM Program	1,277,817	1,277,817	0	0
		Revenue - Other Ele-NonAffiliated	**3,123,765**	**3,120,506**	**-**	**3,259**
		Revenue - Gas	**-**	**-**	**-**	**-**
4118004		Comp Allow Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,533**	**-**	**8,533**	**-**
	A	**Revenue - Other Ele-NonAffiliated**	**3,132,298**	**3,120,506**	**8,533**	**3,259**
		Revenue - Other Opr Electric	**3,184,192**	**3,277,770**	**81,416,598**	**3,259**
	D	**Revenue Merchandising & Contract Work**	**-**	**-**	**-**	**-**
	C	**Revenues Non-Utility Operations - Affiliated**	**-**	**-**	**-**	**-**
	D	**Revenues Non-Utility Operations - NonAffiliated**	**-**	**-**	**-**	**-**
		Revenues from Non-Utility Operations	**-**	**-**	**-**	**-**
	C	**Non-Operating Rental Income - Affiliated**	**-**	**-**	**-**	**-**
4180001		Non-Operatng Rental Income	5,200	5,000	200	0
4180005		Non-Opraing Rntal Inc-Depr	(1,112)	0	0	(1,112)
	D	**Non-Operating Rental Income - NonAffiliated**	**4,088**	**5,000**	**200**	**(1,112)**
		Non-Operating Rental Income	**4,088**	**5,000**	**200**	**(1,112)**
	C	**Non-Operating Misc Income -Affiliated**	**-**	**-**	**-**	**-**
4210002		Misc Non-Op Inc-NonAsc-Rents	397	118	205	74
4210007		Misc Non-Op Inc - NonAsc - Oth	170	124	46	0
	D	**Non-Operating Misc Income - NonAffiliated**	**567**	**242**	**251**	**74**
		Non-Operating Misc Income	**567**	**242**	**251**	**74**
4540004		Rent From Elect Prop-ABD-Nonaf	10,290	10,290	0	0

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			Kentucky Power Int Consol GLS8016 Actual YTD Feb 2014	Kentucky Power Company - Distribution 110 Actual YTD Feb 2014	Kentucky Power Company - Generation 117 Actual YTD Feb 2014	Kentucky Power Company - Transmission 180 Actual YTD Feb 2014
4560015		Other Electric Revenues - ABD	44,087	51,277	0	(7,190)
	D	**Associated Business Development Income**	**54,377**	**61,567**	**-**	**(7,190)**
		Revenue - Other Opr - Other	**59,033**	**66,809**	**451**	**(8,228)**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***59,033***	***66,809***	***451***	***(8,228)***
		Revenue - Other Operating	**3,243,224**	**3,344,578**	**81,417,049**	**(4,968)**
	A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	-	-	-	-
4210031		Pwr Sales Outside Svc Territry	1,561	0	1,561	0
4210032		Pwr Purch Outside Svc Territry	(258)	0	(258)	0
	A	**Revenue - Power Sales**	**1,304**	**-**	**1,304**	**-**
		TOTAL OPERATING REVENUES	**162,764,786**	**116,216,632**	**118,953,506**	**15,738,538**
=(A)		*Memo: G/T/D Revenue*	*157,235,771*	*115,992,559*	*38,181,189*	*3,062,023*
=(B)		*Memo: Other Affiliated Revenue*	*5,469,983*	*157,264*	*80,771,866*	*12,684,742*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Non*	*59,033*	*66,809*	*451*	*(8,228)*
		Memo: Total Operating Revenues	*162,764,786*	*116,216,632*	*118,953,506*	*15,738,538*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***5,469,983***	***157,264***	***80,771,866***	***12,684,742***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***157,294,804***	***116,059,368***	***38,181,640***	***3,053,795***
		Memo: Total Operating Revenues	***162,764,786***	***116,216,632***	***118,953,506***	***15,738,538***
		FUEL EXPENSES				
5010000		Fuel	22,004	0	22,004	0
5010001		Fuel Consumed	54,550,719	0	54,550,719	0
5010003		Fuel - Procure Unload & Handle	2,635,480	0	2,635,480	0
5010013		Fuel Survey Activity	457,589	0	457,589	0
5010019		Fuel Oil Consumed	1,352,107	0	1,352,107	0
5010027		Gypsum handling/disposal costs	28,998	0	28,998	0
5010028		Gypsum Sales Proceeds	(181,803)	0	(181,803)	0
		Fuel Expense Total	**58,865,094**	**-**	**58,865,094**	**-**
5010005		Fuel - Deferred	(8,511,254)	0	(8,511,254)	0
		Deferred Fuel Expense	**(8,511,254)**	**-**	**(8,511,254)**	**-**
		Over Under Fuel Expense				
		Fuel for Electric Generation	**50,353,840**	**-**	**50,353,840**	**-**
5010029		Gypsum handling/displ-Affiliat	18,031	0	18,031	0
		Fuel from Affiliates for Electric Generation	**18,031**	**-**	**18,031**	**-**
5090000		Allow Consum Title IV SO2	1,713,733	0	1,713,733	0
5090005		An NOx Cons Exp	26,817	0	26,817	0
		Allowances - Consumption	**1,740,550**	**-**	**1,740,550**	**-**
5020002		Urea Expense	979,286	0	979,286	0
5020003		Trona Expense	59,155	0	59,155	0
5020004		Limestone Expense	586,393	0	586,393	0
5020005		Polymer expense	10,285	0	10,285	0
5020007		Lime Hydrate Expense	1,452	0	1,452	0
		Emissions Control - Chemicals	**1,636,572**	**-**	**1,636,572**	**-**
		Total Fuel for Electric Generation	**53,748,992**	**-**	**53,748,992**	**-**
		Memo: NonAff Fuel/Allow/Emissions	***53,730,961***	**-**	***53,730,961***	**-**
5550004		Purchased Power Pool Capacity	181,949	0	181,949	0
5550005		Purchased Power - Pool Energy	676,093	0	676,093	0
5550027		Purch Pwr Non-Fuel Portion-Aff	7,950,750	0	7,950,750	0
5550029		Purch Power-Assoc-Trnsfr Price	0	81,408,065	0	0
5550046		Purch Power-Fuel Portion-Affil	11,852,306	0	11,852,306	0
5550101		Purch Power Pool Non-Fuel -Aff	168,508	0	168,508	0
5550102		Pur Power-Pool NonFuel-OSS-Aff	214,985	0	214,985	0
		Purchased Electricity from AEP - Affiliates	**21,044,591**	**81,408,065**	**21,044,591**	**-**
5550001		Purch Pwr-NonTrading-Nonassoc	200,515	0	200,515	0
5550032		Gas-Conversion-Mone Plant	(7,387)	0	(7,387)	0
5550039		PJM Inadvertent Mtr Res-OSS	(66,982)	0	(66,982)	0
5550040		PJM Inadvertent Mtr Res-LSE	(21,163)	0	(21,163)	0
5550041		PJM Ancillary Serv - Sync	590	0	590	0
5550074		PJM Reactive-Charge	(172,902)	0	(172,902)	0
5550076		PJM Black Start-Charge	216,063	0	216,063	0
5550077		PJM Black Start-Credit	(4,258)	0	(4,258)	0
5550078		PJM Regulation-Charge	673,865	0	673,865	0
5550079		PJM Regulation-Credit	(241,407)	0	(241,407)	0
5550083		PJM Spinning Reserve-Charge	858,025	0	858,025	0

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5550084	PJM Spinning Reserve-Credit	(234,602)	0	(234,602)	0
5550090	PJM 30m Suppl Rserv Charge LSE	385,242	0	385,242	0
5550099	PJM Purchases-non-ECR-Auction	819,959	0	819,959	0
5550100	Capacity Purchases-Auction	14,258	0	14,258	0
5550107	Capacity purchases - Trading	18,091	0	18,091	0
	Purchased Electricity for Resale - NonAffiliated	**2,437,906**	-	**2,437,906**	-
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	**23,482,497**	**81,408,065**	**23,482,497**	-
	GROSS MARGIN	**85,533,298**	**34,808,586**	**41,722,018**	**15,738,638**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	623,260	0	623,260	0
5000001	Oper Super & Eng-RATA-Affil	21,000	0	21,000	0
5020000	Steam Expenses	406,724	0	406,724	0
5050000	Electric Expenses	93,520	0	93,520	0
5060000	Misc Steam Power Expenses	1,508,099	0	1,508,099	0
5060002	Misc Steam Power Exp-Assoc	11,495	0	11,495	0
5060003	Removal Cost Expense - Steam	(77,649)	0	(77,649)	0
5060004	NSR Settlement Expense	(1,427)	0	(1,427)	0
5060025	Misc Stm Pwr Exp Environmental	53	0	53	0
	Steam Generation Op Exp	**2,585,075**	-	**2,585,075**	-
	Nuclear Generation Op Exp	-	-	-	-
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	78,599	8	78,330	261
5570000	Other Expenses	284,023	(283)	284,016	290
5570007	Other Pwr Exp - Wholesale RECs	1,654	1,654	0	0
5757000	PJM Admin-MAM&SC- OSS	109,586	0	109,586	0
5757001	PJM Admin-MAM&SC- Internal	165,303	0	165,303	0
	Other Generation Op Exp	**639,164**	**1,379**	**637,234**	**551**
5600000	Oper Supervision & Engineering	163,842	131	625	163,087
5611000	Load Dispatch - Reliability	1,963	0	0	1,963
5612000	Load Dispatch-Mntr&Op TransSys	129,184	29	48	129,107
5614000	PJM Admin-SSC&DS-OSS	95,895	0	95,895	0
5614001	PJM Admin-SSC&DS-Internal	145,028	0	145,028	0
5615000	Reliability Plng&Stds Develop	14,325	1,301	1,772	11,253
5618000	PJM Admin-RP&SDS-OSS	30,929	0	30,929	0
5618001	PJM Admin-RP&SDS- internal	44,783	0	44,783	0
5620001	Station Expenses - Nonassoc	39,726	0	0	39,726
5630000	Overhead Line Expenses	19,575	0	0	19,575
5650002	Transmssn Elec by Others-NAC	43,719	0	43,719	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	6,630,454	0	0
5650012	PJM Trans Enhancement Charge	645,394	0	645,394	0
5650015	PJM TO Serv Exp - Aff	11,871	0	11,871	0
5650016	PJM NITS Expense - Affiliated	608,967	0	608,967	0
5650019	Affil PJM Trans Enhncement Exp	32,141	0	32,141	0
5650020	PROVISION PJM NITS Affl Expens	(62,726)	0	(62,726)	0
5660000	Misc Transmission Expenses	220,217	2,124	2,301	215,792
5670002	Rents - Associated	0	0	0	105,370
	Transmission Op Exp	**2,184,832**	**6,634,039**	**1,600,746**	**685,871**
5800000	Oper Supervision & Engineering	112,371	110,630	716	1,025
5810000	Load Dispatching	949	398	0	551
5820000	Station Expenses	30,754	25,852	0	4,902
5830000	Overhead Line Expenses	133,572	133,572	0	0
5840000	Underground Line Expenses	12,035	12,035	0	0
5850000	Street Lighting & Signal Sys E	12,864	12,864	0	0
5860000	Meter Expenses	105,329	105,101	2	226
5870000	Customer Installations Exp	22,251	22,251	0	0
5880000	Miscellaneous Distribution Exp	726,551	720,620	911	5,021
5890001	Rents - Nonassociated	228,926	228,926	0	0
5890002	Rents - Associated	13,304	13,304	0	0
	Distribution Op Exp	**1,398,907**	**1,385,554**	**1,629**	**11,725**
9010000	Supervision - Customer Accts	44,975	44,975	0	0
9020000	Meter Reading Expenses	4,680	4,600	59	21
9020002	Meter Reading - Regular	59,385	59,385	0	0
9020003	Meter Reading - Large Power	7,390	7,390	0	0
9020004	Read-In & Read-Out Meters	10,813	10,813	0	0
9030000	Cust Records & Collection Exp	52,254	50,924	246	1,084

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		Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		GLS8016	110	117	180
		Actual	Actual	Actual	Actual
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9030001	Customer Orders & Inquiries	370,847	370,706	141	0
9030002	Manual Billing	5,961	5,718	5	238
9030003	Postage - Customer Bills	122,561	122,561	0	0
9030004	Cashiering	16,105	15,453	325	327
9030005	Collection Agents Fees & Exp	4,947	4,947	0	0
9030006	Credit & Oth Collection Actvi	105,861	105,857	3	1
9030007	Collectors	82,133	82,133	0	0
9030009	Data Processing	26,806	26,806	0	0
9040007	Uncoll Accts - Misc Receivable	2,116	(2,608)	4,725	0
9050000	Misc Customer Accounts Exp	2,531	2,531	0	0
9070000	Supervision - Customer Service	22,596	22,598	(1)	(1)
9070001	Supervision - DSM	(7)	(3)	(2)	(2)
9080000	Customer Assistance Expenses	77,824	77,808	8	8
9080001	DSM-Customer Advisory Grp	862	862	0	0
9080009	Cust Assistance Expense - DSM	1,106,380	1,105,969	293	118
9090000	Information & Instruct Advrts	10,520	3,139	5,411	1,970
9100000	Misc Cust Svc&Informational Ex	1,424	875	446	102
	Customer Service and Information Op Exp	**2,138,965**	**2,123,438**	**11,658**	**3,869**
9120000	Demonstrating & Selling Exp	2,692	2,692	0	0
9120003	Demo & Selling Exp - Area Dev	(321)	(321)	0	0
	Sales Expenses	**2,371**	**2,371**	**-**	**-**
	Memo: Insurance (9240 9250)	**306,620**	**107,132**	**158,850**	**40,638**
9200000	Administrative & Gen Salaries	1,397,803	640,442	548,367	208,994
9210001	Off Supl & Exp - Nonassociated	202,530	123,797	45,332	33,400
9220000	Administrative Exp Trnsf - Cr	(93,481)	(93,481)	(0)	0
9220001	Admin Exp Trnsf to Cnstrctn	(81,042)	(81,042)	0	0
9220004	Admin Exp Trnsf to ABD	(528)	(528)	0	0
9230001	Outside Svcs Empl - Nonassoc	208,156	83,883	89,501	34,773
9230003	AEPSC Billed to Client Co	(26,428)	(7,761)	(12,611)	(6,056)
9240000	Property Insurance	77,733	27,513	18,061	32,159
9250000	Injuries and Damages	191,437	139,869	43,064	8,504
9250001	Safety Dinners and Awards	190	140	45	5
9250002	Emp Accident Prvntion-Adm Exp	1,157	897	206	54
9250004	Injuries to Employees	105	0	105	0
9250006	Wkrs Cmpnstn Pre&Slf Ins Prv	(29,593)	(34,221)	3,885	744
9250007	Prsnal Injries&Prop Dmage-Pub	96,608	36	96,544	28
9250010	Frg Ben Loading - Workers Comp	(31,018)	(27,101)	(3,059)	(857)
9260000	Employee Pensions & Benefits	864	864	0	0
9260001	Edit & Print Empl Pub-Salaries	2,045	733	840	472
9260002	Pension & Group Ins Admin	9,062	5,637	2,841	584
9260003	Pension Plan	702,349	369,612	287,421	45,316
9260004	Group Life Insurance Premiums	25,477	10,401	13,366	1,709
9260005	Group Medical Ins Premiums	790,133	438,840	278,718	72,575
9260006	Physical Examinations	1	0	0	1
9260007	Group L-T Disability Ins Prem	2,468	1,397	860	211
9260009	Group Dental Insurance Prem	42,317	24,241	14,755	3,321
9260010	Training Administration Exp	33	16	16	2
9260012	Employee Activities	326	103	130	93
9260014	Educational Assistance Pmts	450	450	0	0
9260021	Postretirement Benefits - OPEB	(548,456)	(289,602)	(218,334)	(40,520)
9260027	Savings Plan Contributions	313,888	137,733	160,690	15,465
9260037	Supplemental Pension	505	505	0	0
9260040	SFAS 112 Postemployment Benef	8,485	0	8,485	0
9260050	Frg Ben Loading - Pension	(148,409)	(115,095)	(26,648)	(6,666)
9260051	Frg Ben Loading - Grp Ins	(215,564)	(171,374)	(31,522)	(12,668)
9260052	Frg Ben Loading - Savings	(93,551)	(57,988)	(30,230)	(5,333)
9260053	Frg Ben Loading - OPEB	56,827	42,555	10,576	3,695
9260055	IntercoFringeOffset- Don't Use	(213,073)	(53,770)	(137,404)	(21,899)
9260057	Postret Ben Medicare Subsidy	89,214	42,507	41,936	4,771
9260058	Frg Ben Loading - Accrual	(53,358)	(27,848)	(25,087)	(423)
9260060	Amort-Post Retirement Benefit	36,103	21,597	11,868	2,639
9270000	Franchise Requirements	23,293	23,293	0	0
9280000	Regulatory Commission Exp	(69)	(10)	(52)	(7)
9280001	Regulatory Commission Exp-Adm	27	12	7	9
9280002	Regulatory Commission Exp-Case	13,024	1,834	9,915	1,275
9301000	General Advertising Expenses	848	298	362	187
9301001	Newspaper Advertising Space	85	30	36	19
9301002	Radio Station Advertising Time	10	4	4	2

American Electric Power

INCOME STATEMENT

GLS8016
YTD Feb 2014
03/10/2014 15:39

Layout: GLS8016

09B V2014-02-28	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Feb 2014	Kentucky Power Company - Distribution 110 Actual YTD Feb 2014	Kentucky Power Company - Generation 117 Actual YTD Feb 2014	Kentucky Power Company - Transmission 180 Actual YTD Feb 2014
9301010	Publicity	1,617	569	691	357
9301012	Public Opinion Surveys	687	687	0	0
9301015	Other Corporate Comm Exp	2,708	2,519	124	64
9302000	Misc General Expenses	77,734	28,273	29,193	20,268
9302003	Corporate & Fiscal Expenses	15,694	2,304	13,364	27
9302004	Research, Develop&Demonstr Exp	661	659	0	1
9310001	Rents - Real Property	15,271	15,271	0	0
9310002	Rents - Personal Property	37,717	23,593	12,191	1,934
	Administration & General	**2,911,073**	**1,253,291**	**1,258,553**	**399,230**
4111005	Accretion Expense	159,372	0	159,372	0
	Accretion	**159,372**	-	**159,372**	-
4116000	Gain From Disposition of Plant	(670)	(670)	0	0
	Loss/(Gain) on Utility Plant	**(670)**	**(670)**	-	-
9302006	Assoc Bus Dev - Materials Sold	18,876	18,876	0	0
9302007	Assoc Business Development Exp	14,584	9,975	43	4,565
	Associated Business Development Expenses	**33,459**	**28,851**	**43**	**4,565**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4265009	Factored Cust A/R Exp - Affil	161,059	161,059	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	361,108	361,108	0	0
	Opr Exp and Factored A/R	**522,166**	**522,166**	-	-
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	9,135	2,896	4,417	1,821
	Expense of Non-Utility Operation	**9,135**	**2,896**	**4,417**	**1,821**
4210009	Misc Non-Op Exp - NonAssoc	2,857	344	2,292	221
	Misc NonOp Expenses - NonAssoc	**2,857**	**344**	**2,292**	**221**
4261000	Donations	100,137	42,806	52,412	4,919
	Donation Contributions	**100,137**	**42,806**	**52,412**	**4,919**
	Provision for Penalties	-	-	-	-
4264000	Civic & Political Activities	50,751	19,088	20,223	11,440
	Civic & Political Activities	**50,751**	**19,088**	**20,223**	**11,440**
4265002	Other Deductions - Nonassoc	18	7	7	4
4265033	Ohio Merger - Transition Costs	4,107	0	4,107	0
	Other Deductions	**4,125**	**7**	**4,114**	**4**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**689,171**	**587,307**	**83,458**	**18,405**
	Operational Expenses	**12,741,719**	**12,015,660**	**6,337,767**	**1,124,216**
5100000	Maint Supv & Engineering	631,962	0	631,962	0
5110000	Maintenance of Structures	407,044	0	407,044	0
5120000	Maintenance of Boiler Plant	1,896,821	0	1,896,821	0
5130000	Maintenance of Electric Plant	568,918	0	568,918	0
5140000	Maintenance of Misc Steam Plt	253,882	0	253,882	0
	Steam Generation Maintenance	**3,758,627**	-	**3,758,627**	-
	Nuclear Generation Maintenance	-	-	-	-
	Hydro Generation Maintenance	-	-	-	-
	Other Generation Maintenance	-	-	-	-
5680000	Maint Supv & Engineering	12,480	0	16	12,464
5690000	Maintenance of Structures	338	0	0	338
5691000	Maint of Computer Hardware	3,806	33	26	3,748
5692000	Maint of Computer Software	54,917	490	0	54,426
5693000	Maint of Communication Equip	4,807	0	0	4,807
5700000	Maint of Station Equipment	173,392	18,062	0	155,331
5710000	Maintenance of Overhead Lines	238,298	68	0	238,230
5720000	Maint of Underground Lines	181	0	0	181
5730000	Maint of Misc Trnsmssion Plt	63,749	0	0	63,749
	Transmission Maintenance	**551,967**	**18,653**	**42**	**533,272**
5900000	Maint Supv & Engineering	589	538	(1)	51
5910000	Maintenance of Structures	3,003	2,294	0	709
5920000	Maint of Station Equipment	127,791	111,707	42	16,042
5930000	Maintenance of Overhead Lines	5,894,514	5,890,473	2,981	1,061
5930001	Tree and Brush Control	54,605	54,605	0	0
5930008	Maint Ovh Lines Strm Exp-OvUnd	1,801	1,801	0	0
5930010	Storm Expense Amortization	783,074	783,074	0	0
5940000	Maint of Underground Lines	15,030	15,030	0	0
5950000	Maint of Lne Trnf Rgltors&Dvi	11,631	11,631	0	0
5960000	Maint of Strt Lghtng & Signal S	10,599	10,599	0	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Feb 2014
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	Layout: GLS8016	Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		GLS8016	110	117	180
		Actual	Actual	Actual	Actual
08B V2014-02-28	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	YTD Feb 2014	YTD Feb 2014	YTD Feb 2014	YTD Feb 2014
5970000	Maintenance of Meters	13,669	12,595	0	1,075
5980000	Maint of Misc Distribution Plt	36,755	36,633	0	122
	Distribution Maintenance	**6,953,062**	**6,930,980**	**3,022**	**19,060**
9350001	Maint of Structures - Owned	27,393	26,680	(117)	830
9350002	Maint of Structures - Leased	7,326	7,322	(0)	4
9350003	Maint of Prprty Held Fture Use	157	1	154	1
9350013	Maint of Cmmncation Eq-Unall	101,568	88,176	13,392	0
9350015	Maint of Office Furniture & Eq	147,617	85,516	62,101	0
9350019	Maint of Gen Plant-SCADA Equ	30	28	2	0
9350024	Maint of DA-AMI Comm Equip	8	8	0	0
	Administration & General Maintenance	**284,099**	**207,732**	**75,532**	**835**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**11,547,764**	**7,157,365**	**3,837,223**	**553,167**
	Total Operational and Maintenance Expenses	**24,289,474**	**19,172,925**	**10,174,990**	**1,677,383**
4040001	Amort. of Plant	559,226	247,504	217,727	93,995
4060001	Amort of Plt Acq Adj	6,436	0	0	6,436
	DDA Amortization	**565,662**	**247,504**	**217,727**	**100,431**
4073000	Regulatory Debits	48,181	0	0	48,181
	DDA Regulatory Debits	**48,181**	-	-	**48,181**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**613,843**	**247,504**	**217,727**	**148,613**
4030001	Depreciation Exp	14,728,539	4,185,054	9,122,400	1,421,084
	DDA Depreciation	**14,728,539**	**4,185,054**	**9,122,400**	**1,421,084**
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	269,327	0	269,327	0
	DDA Asset Retirement Obligation	**269,327**	-	**269,327**	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**14,997,866**	**4,185,054**	**9,391,727**	**1,421,084**
	Depreciation and Amortization	**15,611,709**	**4,432,558**	**9,609,454**	**1,569,697**
	Franchise Taxes	-	-	-	-
408100513	State Gross Receipts Tax	(5,942)	1	(5,943)	0
408100514	State Gross Receipts Tax	10,000	0	10,000	0
	Revenue-kWhr Taxes	**4,058**	**1**	**4,057**	-
4081002	FICA	722,497	307,389	380,880	34,228
4081003	Federal Unemployment Tax	17,713	7,633	9,195	884
4081007	State Unemployment Tax	56,660	19,097	35,347	2,216
4081033	Fringe Benefit Loading - FICA	(171,262)	(106,125)	(55,137)	(10,001)
4081034	Fringe Benefit Loading - FUT	(909)	(692)	(155)	(61)
4081035	Fringe Benefit Loading - SUT	(1,933)	(1,499)	(311)	(122)
	Payroll Taxes	**622,767**	**225,804**	**369,820**	**27,143**
408102014	State Business Occup Taxes	662,095	0	662,095	0
	Capacity Taxes	**662,095**	-	**662,095**	-
408100510	Real Personal Property Taxes	131	131	0	0
408100512	Real Personal Property Taxes	476,666	0	476,666	0
408100513	Real Personal Property Taxes	1,705,340	998,874	150,486	555,980
408102913	Real-Pers Prop Tax-Cap Leases	1,042	792	68	182
408102914	Real-Pers Prop Tax-Cap Leases	3,582	2,704	208	670
408103613	Real Prop Tax-Cap Leases	(1,473)	(1,473)	0	0
408103614	Real Prop Tax-Cap Leases	4,250	4,250	0	0
408200513	Real Personal Property Taxes	9,434	1,612	0	7,822
	Property Taxes	**2,198,972**	**1,006,889**	**627,429**	**564,654**
408101813	St Publ Serv Comm Tax Fees	157,707	157,707	0	0
	Regulatory Fees	**157,707**	**157,707**	-	-
	Production Taxes	-	-	-	-
408101900	State Sales and Use Taxes	5,900	2,500	3,300	100
408101913	State Sales and Use Taxes	1,295	1,295	0	0
408101914	State Sales and Use Taxes	2,211	2,211	0	0
	Miscellaneous Taxes	**9,405**	**6,005**	**3,300**	**100**
	Other Non-Income Taxes	**9,405**	**6,005**	**3,300**	**100**
	Taxes Other Than Income Taxes	**3,665,004**	**1,396,407**	**1,666,700**	**591,897**
	TOTAL OPERATING EXPENSES	**43,566,187**	**25,001,890**	**21,451,144**	**3,838,977**
	Memo. SEC Total Operating Expenses	**120,787,675**	**106,409,955**	**98,682,632**	**3,838,977**
	OPERATING INCOME	**41,977,111**	**9,806,677**	**20,270,874**	**11,899,560**

NON-OPERATING INCOME / (EXPENSES)

American Electric Power

INCOME STATEMENT

GLS8016
YTD Feb 2014
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Layout: GLS8016
09B V2014-02-28 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account	Description	Kentucky Power Int Consol GLS8016 Actual YTD Feb 2014	Kentucky Power Company - Distribution 110 Actual YTD Feb 2014	Kentucky Power Company - Generation 117 Actual YTD Feb 2014	Kentucky Power Company - Transmission 180 Actual YTD Feb 2014
4190002	Int & Dividend Inc - Nonassoc	3,609	3,580	29	0
	Interest & Dividend NonAffiliated	**3,609**	**3,580**	**29**	-
4190001	Interest Inc - Assoc Non CBP	2,137	2,137	0	0
4190005	Interest Income - Assoc CBP	8,702	1,121	(25,942)	33,523
	Interest & Dividend Affiliated	**10,839**	**3,258**	**(25,942)**	**33,523**
	Total Interest & Dividend Income	**14,448**	**6,838**	**(25,913)**	**33,523**
4210039	Carrying Charges	11,088	0	0	11,088
	Interest & Dividend Carrying Charge	**11,088**	-	-	**11,088**
	Memo: Total Interest & Dividend Income w/ Carrying	**25,536**	**6,838**	**(25,913)**	**44,611**
4191000	Allw Oth Fnds Usd Dring Cnstr	916,275	83,672	580,911	251,692
	AFUDC	**916,275**	**83,672**	**580,911**	**251,692**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
	Interest LTD IPC	-	-	-	-
4300001	Interest Exp - Assoc Non-CBP	175,000	69,561	51,482	53,958
	Interest LTD Notes Payable - Affiliated	**175,000**	**69,561**	**51,482**	**53,958**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	5,666,451	2,252,358	1,666,957	1,747,137
	Interest LTD Senior Unsecured	**5,666,451**	**2,252,358**	**1,666,957**	**1,747,137**
4270012	PCRB Interest Exp-Assoc	2,137	2,137	0	0
	Interest LTD Other - Affil	**2,137**	**2,137**	-	-
4270005	Int on LTD - Other LTD	472,569	479,167	(6,597)	0
	Interest LTD Other - NonAffil	**472,569**	**479,167**	**(6,597)**	-
	Interest on Long-Term Debt	**6,316,158**	**2,803,222**	**1,711,841**	**1,801,095**
4300003	Int to Assoc Co - CBP	2,299	(219)	32,059	(29,541)
	Interest STD - Affil	**2,299**	**(219)**	**32,059**	**(29,541)**
4310007	Lines Of Credit	129,148	55,960	61,509	11,679
	Interest STD - NonAffil	**129,148**	**55,960**	**61,509**	**11,679**
	Interest on Short Term Debt	**131,447**	**55,741**	**93,567**	**(17,862)**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	78,531	31,215	23,102	24,213
	Amort of Debt Disc. Prem & Exp	**78,531**	**31,215**	**23,102**	**24,213**
4281004	Amrtz Loss Rcquired Debt-Dbnt	5,608	2,435	1,316	1,857
	Amort Loss on Reacquired Debt	**5,608**	**2,435**	**1,316**	**1,857**
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	1,462	0	35	1,427
4310002	Interest on Customer Deposits	3,766	3,766	0	0
	Other Interest - NonAffil	**5,228**	**3,766**	**35**	**1,427**
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(517,870)	(46,711)	(330,644)	(140,516)
	AFUDC-Borrowed Funds	**(517,870)**	**(46,711)**	**(330,644)**	**(140,516)**
	Total Interest Charges	**6,019,101**	**2,849,669**	**1,499,216**	**1,670,214**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**36,899,820**	**7,047,617**	**19,326,654**	**10,525,650**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	10,715,595	2,967,876	4,789,880	2,957,840
4092001	Inc Tax, Oth Inc&Ded-Federal	(124,452)	(72,830)	(47,343)	(4,280)
	Federal Current Income Tax	**10,591,143**	**2,895,046**	**4,742,536**	**2,953,560**
4101001	Prov Def I/T Util Op Inc-Fed	7,337,679	475,619	6,257,544	604,517
4102001	Prov Def I/T Oth I&D - Federal	89,143	62,542	14,903	11,698
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(6,296,481)	(1,270,107)	(4,799,189)	(227,186)
	Federal Deferred Income Tax	**1,130,341**	**(731,946)**	**1,473,258**	**389,029**
4114001	ITC Adj, Utility Oper - Fed	(16,007)	(2,520)	(3,852)	(9,635)
	Federal Investment Tax Credits	**(16,007)**	**(2,520)**	**(3,852)**	**(9,635)**
	Federal Income Taxes	**11,705,477**	**2,160,580**	**6,211,942**	**3,332,956**
409100214	Income Taxes UOI - State	1,901,238	427,224	960,154	513,860
409200214	Inc Tax Oth Inc Ded - State	(21,601)	(12,641)	(8,217)	(743)
	State Current Income Tax	**1,879,637**	**414,583**	**951,937**	**513,117**
4111002	Prv Def I/T-Cr Util Opinc-State	(101,920)	0	(101,920)	0
	State Deferred Income Tax	**(101,920)**	-	**(101,920)**	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	**1,777,717**	**414,583**	**850,017**	**513,117**
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-

American Electric Power

GLS8016
YTD Feb 2014
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INCOME STATEMENT

Layout: GLS8016

09B V2014-02-26 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8016 Actual YTD Feb 2014	Kentucky Power Company - Distribution 110 Actual YTD Feb 2014	Kentucky Power Company - Generation 117 Actual YTD Feb 2014	Kentucky Power Company - Transmission 180 Actual YTD Feb 2014
Local Income Taxes	-	-	-	-
Foreign Current Income Tax	-	-	-	-
Foreign Deferred Income Tax	-	-	-	-
Foreign Investment Tax Credits	-	-	-	-
Foreign Income Taxes	-	-	-	-
Total Income Taxes	13,483,194	2,575,163	7,061,959	3,846,072
Equity Earnings of Subs	-	-	-	-
INCOME AFTER INCOME TAXES and EQUITY EARNINGS	23,416,626	4,472,354	12,264,695	6,679,578
Discontinued Operations (Net of Taxes)	-	-	-	-
Cumulative Effect of Accounting Changes	-	-	-	-
Extraordinary Income / (Expenses)	-	-	-	-
NET INCOME	23,416,626	4,472,354	12,264,695	6,679,578

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Feb 2014
03/11/2014 14:15

Layout : GLS8216
09B V2014-02- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Feb 2014	YTD Feb 2014	YTD Feb 2014	YTD Feb 2014
ASSETS				
Cash and Cash Equivalents	423,882	423,882	0	0
Other Cash Deposits	0	0	0	0
Customers	25,497,465	12,116,958	12,497,104	883,403
Accrued Unbilled Revenues	(7,129,946)	(7,129,946)	0	0
Miscellaneous Accounts Receivable	32,573,459	7,450,959	75,285,435	8,212,499
Allowances for Uncollectible Accounts	(86,581)	(74,953)	(11,628)	0
Accounts Receivable	50,854,396	12,363,017	87,770,912	9,095,901
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	94,697,620	2,471,405	91,339,814	886,402
Risk Management Contracts - Current	4,591,897	(7,257)	4,599,154	0
Margin Deposits	1,967,967	32,420	1,935,547	0
Unrecovered Fuel - Current	5,660,616	0	5,660,616	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	3,225,779	2,794,886	334,854	96,038
TOTAL CURRENT ASSETS	161,422,157	18,078,354	191,640,896	10,078,341
Electric Production	1,059,605,944	740,748,427	1,491,072,109	507,072,840
Electric Transmission	510,696,781	0	0	0
Electric Distribution	696,709,132	0	0	0
General Property, Plant and Equipment	477,410,955	199,571	4,169,386	1,160,479
Construction Work-In-Progress	135,291,108	14,232,273	85,070,414	35,988,421
TOTAL PROPERTY, PLANT and EQUIPMENT	2,879,713,920	755,180,271	1,580,311,909	544,221,740
less: Accumulated Depreciation and Amortization	(955,403,674)	(234,058,076)	(554,071,655)	(167,273,944)
NET PROPERTY, PLANT and EQUIPMENT	1,924,310,245	521,122,196	1,026,240,254	376,947,796
Net Regulatory Assets	215,450,098	103,515,057	56,327,294	55,607,747
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments In Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	3,173,940	0	3,173,940	0
Employee Benefits and Pension Assets	14,206,025	5,375,808	8,218,881	611,337
Other Non Current Assets	16,436,094	6,517,283	6,526,023	3,392,789
TOTAL OTHER NON-CURRENT ASSETS	249,266,157	115,408,148	74,246,137	59,611,872
TOTAL ASSETS	2,334,998,559	654,608,697	1,292,127,288	446,638,009
LIABILITIES				
Accounts Payable	77,087,633	66,308,807	65,845,715	3,308,545
Advances from Affiliates	33,750,577	(12,408,243)	171,786,167	(125,627,348)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	0	0	0	0
Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
Risk Management Liabilities	966,638	0	966,638	0
Accrued Taxes	22,667,123	8,655,533	3,554,106	10,457,484
Memo: Property Taxes	13,808,462	6,247,334	3,671,765	3,889,363
Accrued Interest	12,448,391	4,936,494	3,695,792	3,816,105
Risk Management Collateral	709,898	12,820	697,078	0
Utility Customer Deposits	24,582,145	24,582,145	0	0
Deposits - Customer and Collateral	25,292,043	24,594,965	697,078	0
Over-Recovered Fuel Costs - Current	0	0	0	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,022,209	496,020	380,778	145,412
Tax Collections Payable	2,692,002	2,580,074	105,513	6,415
Revenue Refunds - Accrued	1,378,946	0	259,350	1,119,596
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	1,664,204	596,954	989,303	77,947
Accrued Rents	(17)	(17)	0	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Feb 2014
03/11/2014 14:15

Layout : GLS8216
09B V2014-02- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

Account	Description	Kentucky Power Int Consol GLS8216 YTD Feb 2014	Kentucky Power Company - 110 YTD Feb 2014	Kentucky Power Company - Generation 117 YTD Feb 2014	Kentucky Power Company - 180 YTD Feb 2014
	Accrued ICP	4,192,558	2,355,147	1,419,263	418,149
	Accrued Vacations	5,630,289	2,172,112	3,199,638	258,538
	Misc Employee Benefits	1,092,373	433,127	652,902	6,345
	Payroll Deductions	225,808	99,824	111,709	14,274
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	717,445	321,461	356,528	39,456
2530022	Customer Advance Receipts	1,165,457	1,165,457	0	0
	Customer Advance	1,165,457	1,165,457	0	0
	Control Cash Disbursement Account	702,336	702,336	0	0
	JMG Liability	0	0	0	0
2420087	Engage to Gain Incentive	(16)	(16)	0	0
2420088	Econ Development Fund Curr	233,000	0	233,000	0
2420512	Unclaimed Funds	4,133	4,133	0	0
2420542	Acc Cash Franchise Req	83,669	83,669	0	0
242059214	Sales Use Tax - Lease Equip	2,067	1,499	411	157
2420643	Accrued Audit Fees	84,018	20,662	50,393	12,963
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	246,141	0	246,141	0
2530050	Deferred Rev -Pole Attachments	118,767	118,767	0	0
2530112	Other Deferred Credits-Curr	262,276	40,660	221,616	0
	Misc Current and Accrued Liabilities	1,588,380	269,373	1,305,887	13,120
	Current Other and Accrued Liabilities	21,049,781	10,695,848	8,400,094	1,953,840
	Other Current Liabilities	22,071,991	11,191,867	8,780,872	2,099,251
	TOTAL CURRENT LIABILITIES	194,284,396	103,279,423	255,326,369	(105,945,962)
	Long-Term Debt - Affiliated	20,000,000	7,949,800	5,883,600	6,166,600
	Long-Term Debt - Non Affiliated	730,000,000	210,669,700	355,915,400	163,414,900
	Long-Term Debt - Premiums and Discounts Unamort	(583,538)	(231,950)	(171,665)	(179,922)
	Memo - LTD NonAffiliated and Premiums	*729,416,463*	*210,437,750*	*355,743,735*	*163,234,978*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	2,014,046	0	2,014,046	0
2440022	L/T Liability MTM Collateral	(46,768)	0	(46,768)	0
	Long-Term Risk Management Liabilities - MTM	1,967,278	0	1,967,278	0
	Long-Term Risk Management Liabilities	1,967,278	0	1,967,278	0
	Deferred Income Taxes	557,315,131	167,570,244	271,537,900	118,206,987
	Deferred Investment Tax Credits	109,740	21,645	33,976	54,120
	Regulatory Liabilities and Deferred Credits	24,892,995	(31,033,876)	62,345,998	(6,419,126)
	Memo - Reg Liab and Def ITC	*25,002,736*	*(31,012,231)*	*62,379,974*	*(6,365,007)*
	Asset Retirement Obligation	20,561,650	61,529	20,500,121	0
	Nuclear Decommissioning	0	0	0	0
	Employee Benefits and Pension Obligations	8,277,484	9,973,661	(2,121,302)	425,125
	Trust Preferred Securities	0	0	0	0
	Cumulative Preferred Stocks of Subs - Mandatory Rede	0	0	0	0
	Obligations Under Capital Leases	3,321,300	1,320,505	1,519,686	481,109
	Def Credits - Income Tax	679,196	360,765	275,890	42,541
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	111,674	111,674	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	6,651	0	6,651	0
2530067	IPP - System Upgrade Credits	270,269	0	0	270,269
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	155,852	155,852	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	100,914	0	0	100,914
	Def Credits - Other	533,686	155,852	6,651	371,184
	Total Other Deferred Credits	645,360	267,526	6,651	371,184
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	932,000	0	932,000	0
	Other Non-Current Liabilities	6,688,499	1,948,796	3,844,870	894,834
	TOTAL NON-CURRENT LIABILITIES	1,369,229,241	366,929,549	719,736,175	282,563,517

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Feb 2014
03/11/2014 14:15

Layout : GLS8216

09B V2014-02- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Feb 2014	Kentucky Power Company - 110 YTD Feb 2014	Kentucky Power Company - Generation 117 YTD Feb 2014	Kentucky Power Company - 180 YTD Feb 2014
TOTAL LIABILITIES	1,563,513,637	470,208,972	975,062,544	176,617,554
Cumulative Pref Stocks of Subs - Not subject Mand Reden	0	0	0	0
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS' EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	539,648,268	106,025,371	349,583,061	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	188,107,550	56,035,479	(36,215,403)	168,287,475
Accumulated Other Comprehensive Income (Loss)	(6,720,896)	(65,174)	(6,590,517)	(65,204)
TOTAL SHAREHOLDERS' EQUITY	771,484,923	184,399,725	317,064,743	270,020,455
Memo: Total Equity	771,484,923	184,399,725	317,064,743	270,020,455
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	2,334,998,560	654,608,697	1,292,127,288	446,638,009

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Feb 2013
02/25/2014 08:58

Layout : GLS8216

09B V2099-01-I Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Feb 2013	YTD Feb 2013	YTD Feb 2013	YTD Feb 2013
ASSETS				
Cash and Cash Equivalents	1,338,992	1,338,992	0	0
Other Cash Deposits	0	0	0	0
Customers	18,482,344	13,244,139	4,410,776	827,429
Accrued Unbilled Revenues	(5,253,508)	(5,253,508)	0	0
Miscellaneous Accounts Receivable	6,159,654	3,863,610	54,818,996	8,494,935
Allowances for Uncollectible Accounts	(9,818)	(9,818)	0	0
Accounts Receivable	19,378,673	11,844,424	59,229,771	9,322,364
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	81,385,556	2,556,860	78,012,147	816,550
Risk Management Contracts - Current	5,411,965	19,786	5,392,179	0
Margin Deposits	1,836,777	34,896	1,801,881	0
Unrecovered Fuel - Current	0	0	0	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	4,308,763	1,668,750	2,501,806	138,207
TOTAL CURRENT ASSETS	113,660,726	17,463,707	146,937,785	10,277,120
Electric Production	560,363,894	706,650,256	569,097,330	495,121,453
Electric Transmission	490,771,562	0	0	0
Electric Distribution	661,487,169	0	0	0
General Property, Plant and Equipment	63,945,918	199,571	4,370,046	1,129,887
Construction Work-In-Progress	41,175,740	12,969,536	1,990,994	26,215,211
TOTAL PROPERTY, PLANT and EQUIPMENT	1,817,744,283	719,819,363	575,458,369	522,466,551
less: Accumulated Depreciation and Amortization	(609,677,017)	(219,193,737)	(228,211,174)	(162,272,106)
NET PROPERTY, PLANT and EQUIPMENT	1,208,067,265	500,625,626	347,247,195	360,194,444
Net Regulatory Assets	212,733,836	122,142,511	34,600,194	55,991,131
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments In Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	5,702,034	0	5,702,034	0
Employee Benefits and Pension Assets	0	0	0	0
Other Non Current Assets	46,405,969	5,341,368	38,165,766	2,898,835
TOTAL OTHER NON-CURRENT ASSETS	264,841,839	127,483,879	78,467,994	58,889,966
TOTAL ASSETS	1,586,569,831	645,573,212	572,652,975	429,361,530
LIABILITIES				
Accounts Payable	43,104,215	66,759,591	33,144,247	4,218,264
Advances from Affiliates	7,643,550	(10,209,489)	132,947,721	(115,094,681)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	0	0	0	0
Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
Risk Management Liabilities	2,978,293	0	2,978,293	0
Accrued Taxes	9,386,650	5,208,600	(3,065,527)	7,243,577
Memo: Property Taxes	10,838,415	4,476,446	3,160,184	3,201,786
Accrued Interest	12,409,136	4,799,440	3,827,072	3,782,624
Risk Management Collateral	44,072	0	44,072	0
Utility Customer Deposits	23,651,603	23,651,603	0	0
Deposits - Customer and Collateral	23,695,675	23,651,603	44,072	0
Over-Recovered Fuel Costs - Current	5,196,081	0	5,196,081	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,300,626	837,229	242,539	220,858
Tax Collections Payable	2,255,985	2,229,827	18,364	7,794
Revenue Refunds - Accrued	3,704,908	1,635,430	14,640	2,054,838
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	905,709	561,010	246,582	98,117
Accrued Rents	(630)	(630)	0	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Feb 2013
02/25/2014 08:58

Layout : GLS8216
09B V2099-01-J Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

		Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
		YTD Feb 2013	YTD Feb 2013	YTD Feb 2013	YTD Feb 2013
	Accrued ICP	3,822,941	2,344,638	1,111,142	367,160
	Accrued Vacations	3,379,217	2,060,099	961,823	357,294
	Misc Employee Benefits	1,118,895	816,491	273,502	28,902
	Payroll Deductions	145,342	85,808	42,227	17,307
	Severance / SEI	463,981	258,527	85,039	120,415
	Accrued Workers Compensation	467,881	338,493	108,880	20,508
2530022	Customer Advance Receipts	1,649,947	1,649,947	0	0
	Customer Advance	1,649,947	1,649,947	0	0
	Control Cash Disbursement Account	1,118,889	1,118,889	0	0
	JMG Liability	0	0	0	0
2420512	Unclaimed Funds	3,657	3,657	0	0
2420542	Acc Cash Franchise Req	89,750	89,750	0	0
242059213	Sales Use Tax - Lease Equip	1,459	1,342	43	75
2420643	Accrued Audit Fees	58,078	25,390	17,279	15,410
2420656	Federal Mitigation Accru (NSR)	376,794	0	376,794	0
2420664	ST State Mitigation Def (NSR)	457,288	0	457,288	0
2530050	Deferred Rev -Pole Attachments	254,169	254,169	0	0
2530112	Other Deferred Credits-Curr	987,973	0	987,973	0
	Misc Current and Accrued Liabilities	2,229,168	374,307	1,839,376	15,485
	Current Other and Accrued Liabilities	21,262,232	13,472,838	4,701,574	3,087,820
	Other Current Liabilities	**22,562,858**	**14,310,067**	**4,944,113**	**3,308,678**
	TOTAL CURRENT LIABILITIES	**126,976,458**	**104,519,812**	**180,016,071**	**(96,541,538)**
	Long-Term Debt - Affiliated	**20,000,000**	**6,907,200**	**7,335,600**	**5,757,200**
	Long-Term Debt - Non Affiliated	**530,000,000**	**197,753,600**	**176,839,800**	**155,406,600**
	Long-Term Debt - Premiums and Discounts Unamort	(750,263)	(279,938)	(250,333)	(219,992)
	Memo - LTD NonAffiliated and Premiums	*529,249,738*	*197,473,662*	*176,589,467*	*155,186,608*
	Long-Term Risk Management Liabilities - Hedge	53,873	4,669	49,204	0
2440002	LT Unreal Losses - Non Affil	3,389,167	0	3,389,167	0
2440022	L/T Liability MTM Collateral	(306,168)	(3,773)	(302,395)	0
	Long-Term Risk Management Liabilities - MTM	3,082,999	(3,773)	3,086,772	0
	Long-Term Risk Management Liabilities	**3,136,872**	**896**	**3,135,976**	**0**
	Deferred Income Taxes	**357,636,437**	**158,877,736**	**90,419,925**	**108,338,776**
	Deferred Investment Tax Credits	**317,424**	**56,456**	**80,414**	**180,554**
	Regulatory Liabilities and Deferred Credits	**25,312,030**	(27,078,421)	**57,419,669**	(5,029,218)
	Memo - Reg Liab and Def ITC	*25,629,454*	*(27,021,965)*	*57,500,083*	*(4,848,663)*
	Asset Retirement Obligation	**3,957,782**	**58,099**	**3,899,683**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**31,372,495**	**19,726,422**	**10,043,543**	**1,602,531**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Rede	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	1,916,115	908,203	705,887	302,025
	Def Credits - Income Tax	1,287,290	370,877	876,869	39,545
2530114	Federl Mitigation Deferal(NSR)	754,942	0	754,942	0
	Def Credits - NSR	754,942	0	754,942	0
2520000	Customer Adv for Construction	58,152	58,152	0	0
	Customer Advances for Construction	58,152	58,152	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530067	IPP - System Upgrade Credits	261,661	0	0	261,661
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	161,672	161,672	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	114,470	0	0	114,470
	Def Credits - Other	537,803	161,672	0	376,131
	Total Other Deferred Credits	595,955	219,824	0	376,131
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**4,554,302**	**1,498,904**	**2,337,697**	**717,701**
	TOTAL NON-CURRENT LIABILITIES	**975,537,080**	**357,520,954**	**351,261,974**	**266,754,152**
	TOTAL LIABILITIES	**1,102,513,538**	**462,040,765**	**531,278,045**	**170,212,614**
	Cumulative Pref Stocks of Subs - Not subject Mand Reden	**0**	**0**	**0**	**0**

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Feb 2013
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Layout : GLS8216

09B V2099-01-4 Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Feb 2013	Kentucky Power Company - 110 YTD Feb 2013	Kentucky Power Company - Generation 117 YTD Feb 2013	Kentucky Power Company - 180 YTD Feb 2013
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	238,750,000	106,025,371	48,684,793	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	195,154,205	55,184,576	(17,462,221)	157,431,850
Accumulated Other Comprehensive Income (Loss)	(297,912)	(81,549)	(135,246)	(81,117)
TOTAL SHAREHOLDERS' EQUITY	484,056,293	183,532,447	41,374,929	259,148,916
Memo: Total Equity	484,056,293	183,532,447	41,374,929	259,148,916
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	1,586,569,831	645,573,212	572,652,975	429,361,530

Revised Final 03/12/2014

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - February, 2014

GLR7210V 03/12/14 11:33

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	4,537,177.40	(1,577,313.98)	(9.12)	0.00	1,481,644,106.18
	TOTAL PRODUCTION	1,478,684,251.88	4,537,177.40	(1,577,313.98)	(9.12)	0.00	1,481,644,106.18
101/106	TRANSMISSION	503,165,571.80	3,131,564.68	(6,647.09)	0.00	0.00	506,290,489.39
101/106	DISTRIBUTION	733,776,590.81	5,218,173.15	(1,444,622.13)	0.00	0.00	737,550,141.83
	TOTAL (ACCOUNTS 101 & 106)	2,715,626,414.49	12,886,915.23	(3,028,583.20)	(9.12)	0.00	2,725,484,737.40
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	(276,468.74)	0.00	6,002,680.43
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	2,721,905,563.66	12,886,915.23	(3,028,583.20)	(276,477.86)	0.00	2,731,487,417.83
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		19,578,874.64				
107000X	TRANSFERS		(12,886,915.23)				
107000X	END. BAL.		6,691,959.41				135,291,107.60
	TOTAL ELECTRIC UTILITY PLANT	2,857,910,670.58	19,578,874.64	(3,028,583.20)	(276,477.86)	0.00	2,874,184,484.16
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-28	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	5,529,435.74	0.00	0.00	(0.03)	0.00	5,529,435.71

Prepared by: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of info. Powerplant Reports and PS GL

Final 03/11/2014

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - February, 2014

GLR7410V 03/11/14 14:43

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
.	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	9,423,330.78	(1,577,313.98)	(100,420.01)	0.00	607,249,723.68
1080001/11	TRANSMISSION	161,537,795.16	1,421,084.42	(6,647.09)	(87,929.62)	0.00	162,864,302.87
1080001/11	DISTRIBUTION	192,744,660.64	4,185,992.96	(1,444,622.13)	(109,855.28)	0.00	195,376,176.19
1080013	PRODUCTION	(3,620,015.26)	0.00	0.00	0.00	(88,350.87)	(3,708,366.13)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698.85)	0.00	0.00	0.00	(1,524.16)	(28,223.01)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(546,834.71)	298,204.91	(8,568,882.32)
	TOTAL (108X accounts)	941,819,616.07	15,030,408.16	(3,028,583.20)	(845,039.62)	208,329.88	953,184,731.29
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	217,726.75	0.00	0.00	84,795.27	10,731,872.89
1110001	TRANSMISSION	1,607,792.68	93,995.44	0.00	0.00	0.00	1,701,788.12
1110001	DISTRIBUTION	7,182,584.75	247,503.81	0.00	0.00	0.00	7,430,088.56
	TOTAL (111X accounts)	19,219,728.30	559,226.00	0.00	0.00	84,795.27	19,863,749.57
1011006	CAPITAL LEASES	1,869,467.09	0.00	0.00	0.00	(210,296.20)	1,659,170.89
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	962,908,811.46	15,589,634.16	(3,028,583.20)	(845,039.62)	82,828.95	974,707,651.75
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	214,955.75	1,111.62	0.00	0.00	0.00	216,067.37
1240027	Other Property - RWIP	(3,400.00)	0.00	0.00	0.00	0.00	(3,400.00)
	TOTAL NONUTILITY PLANT	211,555.75	1,111.62	0.00	0.00	0.00	212,667.37

Prepared by: PSnVision Report GLR7410V
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215 2373
AEP.com

March 27, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed Form EIA-826, Monthly Electric Utility Sales and Revenue Report with State Distributions for the month of February 2014.

Sincerely,

Brian J. Frantz
Manager –Regulated Accounting

BJF
Enclosure

U.S. Department of Energy
Energy Information Administration
Form EIA-826

Monthly Electric Utility Sales and Revenue Report with State Distributions – 2014

Form Approval
OMB NO.1905-0129
(Expires 11-30-2007)

This report is mandatory under Public Law 93-275, the Federal Energy Administration Act of 1974, Public Law 95-91, Department of Energy Organization Act, and Public Law 102-486, the Energy Policy Act of 1992. Information reported on the Form EIA-826 is not considered confidential. See Section V of the General Instructions for sanctions statement. Public reporting burden for this collection of information is estimated to average 1.5 hours per response, including the time for reviewing the instructions, searching existing data sources, gathering and maintaining the data needed, and completing and reviewing the collected information. Send comments regarding this form, its burden estimate, or any aspect of the data collection to the Energy Information Administration, Statistical and Methods Group EI-73, 1000 Independence Avenue S.W., Forrestal Building, Washington, D.C. 20585, and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, D.C. 20503. (A person is required to respond to the collection of information only if it displays a valid OMB number.) **Carefully read and follow all instructions. If you need assistance, please contact Alfred Pippi at: (202) 287-1625 or Charlene Harris-Russell at: (202) 287-1747 or by E-Mail at eia-826@eia.doe.gov.**

Please submit by the last calendar day of the month following the reporting month. **Return completed forms by E-Mail at eia-826@eia.doe.gov or fax to (202) 287-1585 or (202) 287-1959.**
Department of Energy, Energy Information Administration (EI-53), BG-076 (EIA-826) Washington, DC 20585-0650

Utility Name: Kentucky Power Company | **Identification Code (Assigned by EIA): 22053**

Reporting for the month of: Jan__ Feb_X_ Mar__ Apr__ May__ Jun__ Jul__ Aug__ Sep__ Oct__ Nov__ Dec__, 2014

Contact Person: Ronald F Davis | **Phone number: 614-716-3525**

Email: rdavis@aep.com | **Fax: 614-716-1449**

RETAIL SALES TO ULTIMATE CONSUMERS

Schedule I - A: Full Service (Energy and Delivery Service (bundled))

Instructions: Enter the reporting month revenue (thousand dollars), megawatthours, and number of consumers for energy and delivery service (bundled) by State and consumer class category

State	Items	Residential	Commercial	Industrial	Transportation	Total
KY	a. Revenue (Thousand Dollars)	$ 25,704	$ 11,440	$ 12,892		50,036
	b. Megwatthours	270,774	108,056	211,383		590,213
	c. Number of consumers	140,091	30,721	1,302		172,114
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					
	a. Revenue (Thousand Dollars)					
	b. Megwatthours					
	c. Number of consumers					

Note

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

April 30, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed March 2014 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-9	Income Statement
1-3	Details of Operating Revenues
4-7	Operating Expenses – Functional Expenses
8-9	Detail Statement of Taxes

Balance Sheet:

10	Balance Sheet – Assets & Other Debits
10-12	Balance Sheet – Liabilities & Other Credits
11-12	Deferred Credits
12	Statement of Retained Earnings

Utility Property:

13-14	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Brian J. Frantz
Manager –Regulated Accounting

American Electric Power

INCOME STATEMENT

GLS8016
YTD Mar 2014
04/07/2014 18:05

Layout: GLS8016
09B V2014-03-31 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

			Kentucky Power Int Consol GLS8016 Actual YTD Mar 2014	Kentucky Power Company - Distribution 110 Actual YTD Mar 2014	Kentucky Power Company - Generation 117 Actual YTD Mar 2014	Kentucky Power Company - Transmission 180 Actual YTD Mar 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	43,225,794	43,420,171	(194,378)	0
4400002		Residential Sales-W/O Space Ht	16,105,915	16,172,611	(66,696)	0
4400005		Residential Fuel Rev	24,637,736	24,637,736	0	0
	A	**Revenue - Residential Sales**	**83,969,445**	**84,230,519**	**(261,074)**	-
4420001		Commercial Sales	20,615,774	20,812,121	(196,348)	0
4420006		Sales to Pub Auth - Schools	3,836,829	3,874,230	(37,401)	0
4420007		Sales to Pub Auth - Ex Schools	3,771,546	3,805,880	(34,335)	0
4420013		Commercial Fuel Rev	10,515,471	10,515,471	0	0
	A	**Revenue - Commercial Sales**	**38,739,619**	**39,007,703**	**(268,083)**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	15,876,826	15,940,526	(63,701)	0
4420004		Ind Sales-NonAffil(Incl Mines)	7,865,471	7,923,880	(58,409)	0
4420016		Industrial Fuel Rev	19,791,671	19,791,671	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**43,533,968**	**43,656,078**	**(122,110)**	-
		Revenue - Industrial Sales	**43,533,968**	**43,656,078**	**(122,110)**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	359,418	360,317	(898)	0
4440002		Public St & Hwy Light Fuel Rev	83,071	83,071	0	0
	A	**Revenue - Other Retail Sales**	**442,489**	**443,388**	**(898)**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**166,685,521**	**167,337,687**	**(652,166)**	-
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	9,827,274
4561033		PJM NITS Revenue - Affiliated	5,927,747	0	0	9,031,956
4561034		PJM TO Adm Serv Rev - Aff	0	0	0	159,287
4561035		PJM Affiliated Trans NITS Cost	(5,910,528)	0	(9,014,737)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(159,287)	0
4561059		Affil PJM Trans Enhancmnt Rev	54,482	0	0	61,634
4561060		Affil PJM Trans Enhancmnt Cost	(54,328)	0	(61,480)	0
4561062		PROVISION PJM NITS Affil- Cost	(191,709)	0	(191,709)	0
4561063		PROVISION PJM NITS Affiliated	(55,916)	0	0	(55,916)
	B	**Revenue - Transmission-Affiliated**	**(230,251)**	-	**(9,447,212)**	**19,044,235**
4470150		Transm Rev -Dedic Whsl/Muni	14,754	0	(166,402)	181,155
4470206		PJM Trans loss credits-OSS	945,253	0	945,253	0
4470207		PJM transm loss charges - LSE	(9,593,295)	0	(9,593,295)	0
4470208		PJM Transm loss credits-LSE	1,612,744	0	1,612,744	0
4470209		PJM transm loss charges-OSS	(6,892,322)	0	(6,892,322)	0
4561002		RTO Formation Cost Recovery	1,750	0	(34,355)	36,104
4561003		PJM Expansion Cost Recov	20,633	0	(21,600)	42,233
4561005		PJM Point to Point Trans Svc	199,955	0	199,955	0
4561006		PJM Trans Owner Admin Rev	70,513	0	0	70,513
4561007		PJM Network Integ Trans Svc	3,574,877	0	0	3,574,877
4561019		Oth Elec Rev Trans Non Affil	18,846	0	0	18,846
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	990	0	0	990
4561029		PJM NITS Revenue Whsl Cus-NAff	669,735	0	0	669,735
4561030		PJM TO Serv Rev Whls Cus-NAff	10,589	0	0	10,589
4561058		NonAffil PJM Trans Enhncmt Rev	83,550	0	0	83,550
4561061		NAff PJM RTEP Rev for Whsl-FR	6,053	0	0	6,053
4561064		PROVISION PJM NITS WhslCus-NAf	(3,154)	0	0	(3,154)
4561065		PROVISION PJM NITS	(19,653)	0	0	(19,653)
	A	**Revenue - Transmission-NonAffiliated**	**(9,278,182)**	-	**(13,950,022)**	**4,671,839**
		Revenue - Transmission	**(9,508,434)**	-	**(23,397,234)**	**23,716,074**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	88,125	0	88,125	0
4470128		Sales for Res-Aff Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,567,383**	-	**5,567,383**	-
4470002		Sales for Resale - NonAssoc	3,131	0	3,131	0
4470006		Sales for Resale-Bookout Sales	5,052,180	0	5,052,180	0
4470010		Sales for Resale-Bookout Purch	(6,651,549)	0	(6,651,549)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	928,407	0	928,407	0
4470028		Sale/Resale - NA - Fuel Rev	(8,069)	0	(8,069)	0
4470033		Whsal/Muni/Pub Auth Base Rev	746,069	0	746,069	0
4470066		PWR Trding Trans Exp-NonAssoc	(39)	0	(39)	0
4470081		Financial Spark Gas - Realized	8,171	0	8,171	0
4470082		Financial Electric Realized	2,541,659	0	2,541,659	0
4470089		PJM Energy Sales Margin	63,847,197	0	63,847,197	0
4470093		PJM Implicit Congestion-LSE	(18,758,235)	0	(18,758,235)	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Mar 2014
04/07/2014 18:05

Layout: GLS8016
098 V2014-03-31 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

			Kentucky Power Int Consol GLS8016 Actual YTD Mar 2014	Kentucky Power Company - Distribution 110 Actual YTD Mar 2014	Kentucky Power Company - Generation 117 Actual YTD Mar 2014	Kentucky Power Company - Transmission 180 Actual YTD Mar 2014
4470098		PJM Oper Reserve Rev-OSS	(2,330,265)	0	(2,330,265)	0
4470099		Capacity Cr Net Sales	128,811	0	128,811	0
4470100		PJM FTR Revenue-OSS	562,296	0	562,296	0
4470101		PJM FTR Revenue-LSE	6,516,487	0	6,516,487	0
4470103		PJM Energy Sales Cost	47,612,228	0	47,612,228	0
4470106		PJM Pt2Pt Trans Purch-NonAff	(27)	0	(27)	0
4470107		PJM NITS Purch-NonAff	25,042	0	25,042	0
4470109		PJM FTR Revenue-Spec	(79,078)	0	(79,078)	0
4470110		PJM TO Admin Exp -NonAff	34,464	0	34,464	0
4470115		PJM Meter Corrections-OSS	(10,107)	0	(10,107)	0
4470116		PJM Meter Corrections-LSE	39,704	0	39,704	0
4470124		PJM Incremental Spot-OSS	0	0	0	0
4470126		PJM Incremental Imp Cong-OSS	(18,610,831)	0	(18,610,831)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	(221,424)	0	(221,424)	0
4470144		Realiz Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim Margin Reclass	(175)	0	(175)	0
4470166		Interest Rate Swaps-Power	(3,285)	0	(3,285)	0
4470170		Non-ECR Auction Sales-OSS	920,663	0	920,663	0
4470174		PJM Whlse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	144,619	0	144,619	0
4470176		OSS Sharing Reclass-Reduction	(144,619)	0	(144,619)	0
4470180		Trading intra-book Reclass	(154,655)	0	(154,655)	0
4470181		Auction intra-book Reclass	154,655	0	154,655	0
4470202		PJM OpRes-LSE-Credit	379,856	0	379,856	0
4470203		PJM OpRes-LSE-Charge	(4,463,352)	0	(4,463,352)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,180	0	28,180	0
4470220		PJM Regulation - OSS	96,188	0	96,188	0
4470221		PJM Spinning Reserve - OSS	7,582	0	7,582	0
4470222		PJM Reactive - OSS	158,295	0	158,295	0
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	(10,423)	0	(10,423)	0
5550080		PJM Hourly Net Purch -FERC	(12,626,982)	0	(12,626,982)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**65,864,386**	-	**65,864,386**	-
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**71,431,769**	-	**71,431,769**	-
4470074		Sale for Resale-Aff Trnf Price	0	0	121,397,976	0
4540001		Rent From Elect Property - Af	77,841	235,895	0	0
	B	**Revenue - Other Ele-Affiliated**	**77,841**	**235,895**	**121,397,976**	-
4500000		Forfeited Discounts	1,197,277	1,197,277	0	0
4510001		Misc Service Rev - Nonaffil	70,242	66,853	0	3,389
4540002		Rent From Elect Property-NAC	36,244	450	34,689	1,105
4540005		Rent from Elec Prop-Pole Attch	1,230,317	1,230,317	0	0
4560007		Oth Elect Rev - DSM Program	1,815,196	1,815,196	0	0
		Revenue - Other Ele-NonAffiliated	**4,349,276**	**4,310,093**	**34,689**	**4,494**
		Revenue - Gas	-	-	-	-
4118002		Comp Allow Gains Title IV SO2	383	0	383	0
4118004		Comp Allow Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,916**	-	**8,916**	-
	A	**Revenue - Other Ele-NonAffiliated**	**4,358,192**	**4,310,093**	**43,605**	**4,494**
		Revenue - Other Opr Electric	**4,436,032**	**4,545,988**	**121,441,581**	**4,494**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	8,800	8,500	300	0
4180005		Non-Opratng Rntal Inc-Depr	(1,667)	0	0	(1,667)
	D	**Non-Operating Rental Income - NonAffiliated**	**7,133**	**8,500**	**300**	**(1,667)**
		Non-Operating Rental Income	**7,133**	**8,500**	**300**	**(1,667)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	1,796	177	1,508	111
4210007		Misc Non-Op Inc - NonAsc - Oth	264	196	68	0
	D	**Non-Operating Misc Income - NonAffiliated**	**2,060**	**373**	**1,575**	**111**
		Non-Operating Misc Income	**2,060**	**373**	**1,575**	**111**
4540004		Rent From Elect Prop-ABD-Nonaf	19,340	19,340	0	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Mar 2014
04/07/2014 18:05

			Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
			GLS8016 Actual	110 Actual	117 Actual	180 Actual
09B V2014-03-31		Layout: GLS8016 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	YTD Mar 2014	YTD Mar 2014	YTD Mar 2014	YTD Mar 2014
4560015		Other Electric Revenues - ABD	55,726	58,874	0	(3,148)
	D	**Associated Business Development Income**	75,066	78,214	-	(3,148)
		Revenue - Other Opr - Other	84,258	87,087	1,875	(4,704)
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	*84,258*	*87,087*	*1,875*	*(4,704)*
		Revenue - Other Operating	4,520,290	4,633,075	121,443,456	(210)
	A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	-	-	-	-
4210031		Pwr Sales Outside Svc Terrtry	1,561	0	1,561	0
4210032		Pwr Purch Outside Svc Terrtry	(258)	0	(258)	0
	A	**Revenue - Power Sales**	1,304	-	1,304	-
		TOTAL OPERATING REVENUES	233,130,450	171,970,762	168,827,129	23,715,864
	=(A)	*Memo: G/T/D Revenue*	*227,681,220*	*171,647,780*	*51,307,107*	*4,676,333*
	=(B)	*Memo: Other Affiliated Revenue*	*5,414,972*	*235,895*	*117,518,146*	*19,044,235*
	=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
	=(D)	*Memo: Revenue-Oth Opr-Oth Non*	*84,258*	*87,087*	*1,875*	*(4,704)*
		Memo: Total Operating Revenues	*233,130,450*	*171,970,762*	*168,827,129*	*23,715,864*
	=(E)=(B)+(C)	***Memo: Affiliated Revenue***	***5,414,972***	***235,895***	***117,518,146***	***19,044,235***
	=(F)=(D)+(A)	***Memo: Non-Affiliated Revenue***	***227,715,478***	***171,734,866***	***51,308,982***	***4,671,629***
		Memo: Total Operating Revenues	***233,130,450***	***171,970,762***	***168,827,129***	***23,715,864***
		FUEL EXPENSES				
5010000		Fuel	79,811	0	79,811	0
5010001		Fuel Consumed	75,229,003	0	75,229,003	0
5010003		Fuel - Procure Unload & Handle	3,575,356	0	3,575,356	0
5010013		Fuel Survey Activity	457,589	0	457,589	0
5010019		Fuel Oil Consumed	1,828,166	0	1,828,166	0
5010027		Gypsum handling/disposal costs	55,110	0	55,110	0
5010028		Gypsum Sales Proceeds	(221,585)	0	(221,585)	0
		Fuel Expense Total	81,003,450	-	81,003,450	-
5010005		Fuel - Deferred	(13,444,284)	0	(13,444,284)	0
		Deferred Fuel Expense	(13,444,284)	-	(13,444,284)	-
		Over Under Fuel Expense				
		Fuel for Electric Generation	67,559,166	-	67,559,166	-
5010029		Gypsum handling/displ-Affiliat	34,868	0	34,868	0
		Fuel from Affiliates for Electric Generation	34,868	-	34,868	-
5090000		Allow Consum Title IV SO2	2,397,999	0	2,397,999	0
5090005		An. NOx Cons. Exp	40,187	0	40,187	0
		Allowances - Consumption	2,438,186	-	2,438,186	-
5020002		Urea Expense	1,253,486	0	1,253,486	0
5020003		Trona Expense	94,364	0	94,364	0
5020004		Limestone Expense	961,573	0	961,573	0
5020005		Polymer expense	19,376	0	19,376	0
5020007		Lime Hydrate Expense	1,452	0	1,452	0
		Emissions Control - Chemicals	2,330,251	-	2,330,251	-
		Total Fuel for Electric Generation	72,362,470	-	72,362,470	-
		Memo: NonAff Fuel/Allow/Emissions	***72,327,602***	-	***72,327,602***	-
5550004		Purchased Power-Pool Capacity	181,949	0	181,949	0
5550005		Purchased Power - Pool Energy	676,093	0	676,093	0
5550027		Purch Pwr-Non-Fuel Portion-Aff	11,758,187	0	11,758,187	0
5550029		Purch Power-Assoc-Trnsfr Price	0	121,397,976	0	0
5550046		Purch Power-Fuel Portion-Affil	18,422,470	0	18,422,470	0
5550101		Purch Power-Pool Non-Fuel -Aff	168,508	0	168,508	0
5550102		Pur Power-Pool NonFuel-OSS-Aff	214,985	0	214,985	0
		Purchased Electricity from AEP - Affiliates	31,422,192	121,397,976	31,422,192	-
5550001		Purch Pwr-NonTrading-Nonassoc	(20,975)	0	(20,975)	0
5550032		Gas-Conversion-Mone Plant	(7,715)	0	(7,715)	0
5550039		PJM Inadvertent Mtr Res-OSS	(72,204)	0	(72,204)	0
5550040		PJM Inadvertent Mtr Res-LSE	(44,283)	0	(44,283)	0
5550041		PJM Ancillary Serv -Sync	590	0	590	0
5550074		PJM Reactive-Charge	(11,793)	0	(11,793)	0
5550076		PJM Black Start-Charge	317,856	0	317,856	0
5550077		PJM Black Start-Credit	(12,006)	0	(12,006)	0
5550078		PJM Regulation-Charge	1,071,793	0	1,071,793	0
5550079		PJM Regulation-Credit	(291,362)	0	(291,362)	0
5550083		PJM Spinning Reserve-Charge	903,220	0	903,220	0
5550084		PJM Spinning Reserve-Credit	(240,043)	0	(240,043)	0
5550090		PJM 30m Suppl Rserv Charge LSE	386,920	0	386,920	0

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09B V2014-03-31	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Mar 2014	Kentucky Power Company - Distribution 110 Actual YTD Mar 2014	Kentucky Power Company - Generation 117 Actual YTD Mar 2014	Kentucky Power Company - Transmission 180 Actual YTD Mar 2014
5550099	PJM Purchases-non-ECR-Auction	1,083,571	0	1,083,571	0
5550100	Capacity Purchases-Auction	21,387	0	21,387	0
5550107	Capacity purchases - Trading	27,588	0	27,588	0
	Purchased Electricity for Resale - NonAffiliated	**3,112,544**	-	**3,112,544**	-
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	**34,534,736**	**121,397,976**	**34,534,736**	-
	GROSS MARGIN	**126,233,244**	**50,572,786**	**51,929,923**	**23,715,864**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	983,993	0	983,993	0
5000001	Oper Super & Eng-RATA-Affl	42,212	0	42,212	0
5020000	Steam Expenses	605,351	0	605,351	0
5050000	Electric Expenses	147,050	0	147,050	0
5060000	Misc Steam Power Expenses	2,149,720	0	2,149,720	0
5060002	Misc Steam Power Exp-Assoc	15,980	0	15,980	0
5060003	Removal Cost Expense - Steam	(71,756)	0	(71,756)	0
5060004	NSR Settlement Expense	(1,427)	0	(1,427)	0
5060025	Misc Stm Pwr Exp Environmental	(11)	0	(11)	0
	Steam Generation Op Exp	**3,871,113**	-	**3,871,113**	-
	Nuclear Generation Op Exp	-	-	-	-
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	143,704	190	142,935	579
5570000	Other Expenses	469,179	111	469,127	(60)
5570007	Other Pwr Exp , Wholesale RECs	10,651	10,651	0	0
5757000	PJM Admin-MAM&SC- OSS	142,607	0	142,607	0
5757001	PJM Admin-MAM&SC- Internal	220,694	0	220,694	(0)
	Other Generation Op Exp	**986,834**	**10,951**	**975,363**	**520**
5600000	Oper Supervision & Engineering	259,104	578	1,236	257,290
5611000	Load Dispatch - Reliability	2,801	0	0	2,801
5612000	Load Dispatch-Mntr&Op TransSys	204,599	29	48	204,522
5614000	PJM Admin-SSC&DS-OSS	122,129	0	122,129	0
5614001	PJM Admin-SSC&DS-Internal	193,166	0	193,166	0
5615000	Reliability Plng&Stds Develop	20,255	2,105	3,115	15,035
5618000	PJM Admin-RP&SDS-OSS	36,623	0	36,623	0
5618001	PJM Admin-RP&SDS- Internal	55,441	0	55,441	0
5620001	Station Expenses - Nonassoc	59,373	0	0	59,373
5630000	Overhead Line Expenses	22,300	0	0	22,300
5650002	Transmssn Elec by Others-NAC	62,283	0	62,283	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	9,827,274	0	0
5650012	PJM Trans Enhancement Charge	970,762	0	970,762	0
5650015	PJM TO Serv Exp - Aff	14,501	0	14,501	0
5650016	PJM NITS Expense - Affiliated	930,256	0	930,256	0
5650019	Affil PJM Trans Enhncement Exp	48,221	0	48,221	0
5650020	PROVISION PJM NITS Aff Expens	(93,970)	0	(93,970)	0
5660000	Misc Transmission Expenses	376,169	2,979	3,504	371,685
5670002	Rents - Associated	0	0	0	158,055
5757002	SPP Admin-MAM&SC	0	0	0	0
	Transmission Op Exp	**3,286,013**	**9,832,965**	**2,347,315**	**1,091,062**
5800000	Oper Supervision & Engineering	245,592	242,765	1,081	1,746
5810000	Load Dispatching	1,313	732	0	581
5820000	Station Expenses	55,224	49,293	0	5,931
5830000	Overhead Line Expenses	206,612	206,550	0	62
5840000	Underground Line Expenses	20,718	20,555	120	44
5850000	Street Lighting & Signal Sys E	27,836	27,836	0	0
5860000	Meter Expenses	190,785	190,495	14	276
5870000	Customer Installations Exp	34,349	34,349	0	0
5880000	Miscellaneous Distribution Exp	1,042,564	1,033,370	1,778	7,416
5890001	Rents - Nonassociated	350,111	350,111	0	0
5890002	Rents - Associated	19,956	19,956	0	0
	Distribution Op Exp	**2,195,061**	**2,176,012**	**2,993**	**16,055**
9010000	Supervision - Customer Accts	73,806	73,733	53	19
9020000	Meter Reading Expenses	1,331	1,174	116	42
9020001	Customer Card Reading	319	95	164	60
9020002	Meter Reading - Regular	96,707	96,707	0	0
9020003	Meter Reading - Large Power	12,025	12,025	0	0
9020004	Read-In & Read-Out Meters	15,044	15,044	0	0
9030000	Cust Records & Collection Exp	95,141	92,969	393	1,778
9030001	Customer Orders & Inquiries	616,867	616,846	22	0

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9030002	Manual Billing	9,355	9,030	5	320
9030003	Postage - Customer Bills	188,973	188,973	0	0
9030004	Cashiering	26,657	25,910	375	372
9030005	Collection Agents Fees & Exp	14,993	14,993	0	0
9030006	Credit & Oth Collection Activi	164,984	164,939	33	12
9030007	Collectors	135,355	135,355	0	0
9030009	Data Processing	40,663	40,651	9	3
9040007	Uncoll Accts - Misc Receivable	(21,846)	(26,570)	4,725	0
9050000	Misc Customer Accounts Exp	8,135	8,135	0	0
9070000	Supervision - Customer Service	36,642	36,647	(3)	(2)
9070001	Supervision - DSM	(11)	(4)	(4)	(3)
9080000	Customer Assistance Expenses	116,067	116,059	4	4
9080001	DSM-Customer Advisory Grp	862	862	0	0
9080009	Cust Assistance Expense - DSM	1,559,113	1,558,400	513	200
9090000	Information & Instruct Advrts	25,614	7,642	13,175	4,797
9100000	Misc Cust Svc&Informational Ex	4,680	2,567	1,664	449
	Customer Service and Information Op Exp	**3,221,477**	**3,192,182**	**21,244**	**8,052**
9120000	Demonstrating & Selling Exp	4,643	4,643	0	0
9120003	Demo & Selling Exp - Area Dev	(321)	(321)	0	0
	Sales Expenses	**4,322**	**4,322**	**-**	**-**
	Memo: Insurance (9240 9250)	**414,317**	**165,378**	**186,080**	**62,860**
9200000	Administrative & Gen Salaries	2,331,640	1,057,994	903,435	370,211
9210001	Off Supl & Exp - Nonassociated	215,175	115,410	67,309	32,455
9220000	Administrative Exp Trnsf - Cr	(132,559)	(132,559)	0	0
9220001	Admin Exp Trnsf to Cnstrctn	(110,515)	(110,515)	0	0
9220004	Admin Exp Trnsf to ABD	(528)	(528)	0	0
9230001	Outside Svcs Empl - Nonassoc	317,284	128,197	138,343	50,745
9230003	AEPSC Billed to Client Co	(77,641)	(25,392)	(31,419)	(20,829)
9240000	Property Insurance	116,989	41,340	27,300	48,349
9250000	Injuries and Damages	267,171	194,116	62,717	10,338
9250001	Safety Dinners and Awards	1,178	488	467	224
9250002	Emp Accident Prvntion-Adm Exp	2,255	1,506	647	102
9250004	Injuries to Employees	732	0	732	0
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(28,543)	(29,244)	(4,664)	5,364
9250007	Prsnal Injries&Prop Dmage-Pub	103,594	11	103,574	9
9250010	Frg Ben Loading - Workers Comp	(49,059)	(42,839)	(4,693)	(1,526)
9260000	Employee Pensions & Benefits	1,270	1,270	0	0
9260001	Edit & Print Empl Pub-Salaries	3,653	1,305	1,514	835
9260002	Pension & Group Ins Admin	14,532	7,981	5,708	843
9260003	Pension Plan	1,207,515	573,403	565,710	68,402
9260004	Group Life Insurance Premiums	38,259	15,529	20,206	2,524
9260005	Group Medical Ins Premiums	1,224,580	643,848	477,954	102,778
9260006	Physical Examinations	1	0	0	1
9260007	Group L-T Disability Ins Prem	3,820	2,023	1,509	287
9260009	Group Dental Insurance Prem	67,413	36,399	26,269	4,746
9260010	Training Administration Exp	42	16	25	2
9260012	Employee Activities	761	138	224	399
9260014	Educational Assistance Pmts	450	450	0	0
9260021	Postretirement Benefits - OPEB	(918,445)	(436,161)	(421,627)	(60,656)
9260027	Savings Plan Contributions	541,900	214,531	306,691	20,678
9260036	Deferred Compensation	1,956	1,956	0	0
9260037	Supplemental Pension	60	60	0	0
9260040	SFAS 112 Postemployment Benef	417,616	0	417,616	0
9260050	Frg Ben Loading - Pension	(234,680)	(181,930)	(40,884)	(11,866)
9260051	Frg Ben Loading - Grp Ins	(341,802)	(270,890)	(48,360)	(22,551)
9260052	Frg Ben Loading - Savings	(153,398)	(95,720)	(47,545)	(10,133)
9260053	Frg Ben Loading - OPEB	90,072	67,267	16,226	6,578
9260055	IntercoFringeOffset- Don't Use	(320,113)	(80,380)	(206,659)	(33,073)
9260057	Postret Ben Medicare Subsidy	155,816	62,297	87,608	5,910
9260058	Frg Ben Loading - Accrual	(86,025)	(59,093)	(23,060)	(3,872)
9260060	Amort Post Retirement Benefit	36,103	21,597	11,868	2,639
9270000	Franchise Requirements	34,749	34,749	0	0
9280000	Regulatory Commission Exp	6,728	2,354	2,863	1,511
9280001	Regulatory Commission Exp-Adm	14	6	3	5
9280002	Regulatory Commission Exp-Case	25,088	3,751	18,846	2,491
9301000	General Advertising Expenses	848	298	362	187
9301001	Newspaper Advertising Space	1,187	418	507	262
9301002	Radio Station Advertising Time	15	5	7	3
9301010	Publicity	1,690	599	724	366
9301012	Public Opinion Surveys	14,238	14,237	0	1

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9301015	Other Corporate Comm Exp	4,567	3,364	794	410
9302000	Misc General Expenses	74,385	27,292	27,962	19,132
9302003	Corporate & Fiscal Expenses	17,042	3,060	13,518	464
9302004	Research, Develop&Demonstr Exp	1,123	1,099	0	23
9302458	AEPSC Non Affiliated expenses	(0)	0	(0)	0
9310001	Rents - Real Property	25,406	25,406	0	0
9310002	Rents - Personal Property	58,706	37,471	18,333	2,902
	Administration & General	**4,974,317**	**1,877,989**	**2,498,657**	**597,671**
4111005	Accretion Expense	239,665	0	239,665	0
	Accretion	**239,665**	-	**239,665**	-
4116000	Gain From Disposition of Plant	(1,005)	(1,005)	0	0
	Loss/(Gain) on Utility Plant	**(1,005)**	**(1,005)**	-	-
9302006	Assoc Bus Dev - Materials Sold	21,004	21,004	0	0
9302007	Assoc Business Development Exp	23,066	14,726	47	8,292
	Associated Business Development Expenses	**44,069**	**35,730**	**47**	**8,292**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4265009	Factored Cust A/R Exp - Affil	235,939	235,939	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	526,664	526,664	0	0
	Opr Exp and Factored A/R	**762,603**	**762,603**	-	-
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	27,131	9,229	12,106	5,796
	Expense of Non-Utility Operation	**27,131**	**9,229**	**12,106**	**5,796**
4210009	Misc Non-Op Exp - NonAssoc	3,267	516	2,424	326
	Misc NonOp Expenses - NonAssoc	**3,267**	**516**	**2,424**	**326**
4261000	Donations	121,630	61,560	54,368	5,703
	Donation Contributions	**121,630**	**61,560**	**54,368**	**5,703**
4263001	Penalties	53,660	18,186	24,097	11,377
	Provision for Penalties	**53,660**	**18,186**	**24,097**	**11,377**
4264000	Civic & Political Activities	70,571	25,864	28,869	15,838
	Civic & Political Activities	**70,571**	**25,864**	**28,869**	**15,838**
4265002	Other Deductions - Nonassoc	47	12	27	7
4265033	Ohio Merger - Transition Costs	4,479	0	4,479	0
	Other Deductions	**4,526**	**12**	**4,507**	**7**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**1,043,388**	**877,970**	**126,370**	**39,048**
	Operational Expenses	**19,865,254**	**18,007,116**	**10,082,768**	**1,760,699**
5100000	Maint Supv & Engineering	950,230	0	950,230	0
5110000	Maintenance of Structures	533,456	0	533,456	0
5120000	Maintenance of Boiler Plant	4,802,554	0	4,802,554	0
5120025	Maint of Blr Plt Environmental	30	0	30	0
5130000	Maintenance of Electric Plant	905,837	0	905,837	0
5140000	Maintenance of Misc Steam Plt	378,305	0	378,305	0
	Steam Generation Maintenance	**7,570,411**	-	**7,570,411**	-
	Nuclear Generation Maintenance	-	-	-	-
	Hydro Generation Maintenance	-	-	-	-
	Other Generation Maintenance	-	-	-	-
5680000	Maint Supv & Engineering	21,517	0	5	21,512
5690000	Maintenance of Structures	1,454	0	0	1,454
5691000	Maint of Computer Hardware	5,680	27	21	5,632
5692000	Maint of Computer Software	76,816	864	0	75,952
5693000	Maint of Communication Equip	6,185	0	0	6,185
5700000	Maint of Station Equipment	237,301	18,114	0	219,187
5710000	Maintenance of Overhead Lines	334,670	(461)	0	335,132
5720000	Maint of Underground Lines	155	0	0	155
5730000	Maint of Misc Trnsmssion Plt	89,897	0	0	89,897
	Transmission Maintenance	**773,674**	**18,545**	**26**	**755,104**
5900000	Maint Supv & Engineering	664	656	(1)	9
5910000	Maintenance of Structures	4,694	4,066	0	628
5920000	Maint of Station Equipment	226,530	216,528	43	9,958
5930000	Maintenance of Overhead Lines	8,190,583	8,186,958	2,602	1,024
5930001	Tree and Brush Control	86,400	86,400	0	0
5930008	Maint Ovh Lines Strm Exp-OvUnd	1,292	1,292	0	0
5930010	Storm Expense Amortization	1,174,611	1,174,611	0	0
5940000	Maint of Underground Lines	26,357	26,357	0	0
5950000	Maint of Line Trnf,Rglators&Dvi	16,688	16,688	0	0
5960000	Maint of Strt Lghtng & Sgnal S	14,807	14,807	0	0
5970000	Maintenance of Meters	23,467	22,385	0	1,082

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5980000	Maint of Misc Distribution Plt	55,645	55,008	0	637
	Distribution Maintenance	9,821,738	9,805,755	2,644	13,338
9350001	Maint of Structures - Owned	75,473	73,593	(159)	2,040
9350002	Maint of Structures - Leased	11,511	11,511	(0)	(0)
9350003	Maint of Prprty Held Fture Use	505	22	466	17
9350006	Maint of Carrier Equipment	13	13	0	0
9350012	Maint of Data Equipment	344	0	344	0
9350013	Maint of Cmmncation Eq-Unall	182,255	165,917	16,338	0
9350015	Maint of Office Furniture & Eq	206,264	96,482	109,782	0
9350019	Maint of Gen Plant-SCADA Equ	78	76	2	0
9350024	Maint of DA-AMI Comm Equip	8	8	0	0
	Administration & General Maintenance	476,453	347,623	126,773	2,057
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	18,642,276	10,171,922	7,699,654	770,499
	Total Operational and Maintenance Expenses	38,507,530	28,179,038	17,782,622	2,531,198
4040001	Amort. of Plant	846,539	374,805	329,538	142,198
4060001	Amort of Plt Acq Adj	9,654	0	0	9,654
	DDA Amortization	856,193	374,805	329,536	151,852
4073000	Regulatory Debits	72,272	0	0	72,272
	DDA Regulatory Debits	72,272	-	-	72,272
	DDA Regulatory Credits	-	-	-	-
	Amortization	928,464	374,805	329,536	224,124
4030001	Depreciation Exp	22,189,405	6,320,992	13,689,804	2,178,610
	DDA Depreciation	22,189,405	6,320,992	13,689,804	2,178,610
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	403,991	0	403,991	0
	DDA Asset Retirement Obligation	403,991	-	403,991	-
	DDA Removal Costs	-	-	-	-
	Depreciation	22,593,396	6,320,992	14,093,795	2,178,610
	Depreciation and Amortization	23,521,661	6,695,797	14,423,330	2,402,734
	Franchise Taxes	-	-	-	-
408100613	State Gross Receipts Tax	(5,942)	1	(5,943)	0
408100614	State Gross Receipts Tax	15,000	0	15,000	0
	Revenue-kWhr Taxes	9,058	1	9,057	-
4081002	FICA	1,094,759	413,793	641,725	39,241
4081003	Federal Unemployment Tax	17,969	7,779	9,306	885
4081007	State Unemployment Tax	57,437	19,471	35,719	2,247
4081033	Fringe Benefit Loading - FICA	(281,080)	(175,258)	(86,713)	(19,109)
4081034	Fringe Benefit Loading - FUT	(1,441)	(1,094)	(239)	(109)
4081035	Fringe Benefit Loading - SUT	(3,065)	(2,370)	(477)	(218)
	Payroll Taxes	884,578	262,321	599,320	22,937
408102014	State Business Occup Taxes	993,143	0	993,143	0
	Capacity Taxes	993,143	-	993,143	-
408100510	Real Personal Property Taxes	131	131	0	0
408100512	Real Personal Property Taxes	714,999	0	714,999	0
408100513	Real Personal Property Taxes	2,557,910	1,498,311	225,629	833,970
408102913	Real-Pers Prop Tax-Cap Leases	1,042	792	68	182
408102914	Real-Pers Prop Tax-Cap Leases	5,373	4,056	312	1,005
408103613	Real Prop Tax-Cap Leases	(1,473)	(1,473)	0	0
408103614	Real Prop Tax-Cap Leases	6,375	6,375	0	0
408200513	Real Personal Property Taxes	14,151	2,418	0	11,733
	Property Taxes	3,298,508	1,510,609	941,009	846,890
408101813	St Publ Serv Comm Tax-Fees	236,561	236,561	0	0
	Regulatory Fees	236,561	236,561	-	-
	Production Taxes	-	-	-	-
408101714	St Lic Rgstrtion Tax-Fees	200	200	0	0
408101900	State Sales and Use Taxes	(342,470)	(156,655)	(178,775)	(7,040)
408101912	State Sales and Use Taxes	218,039	89,065	119,078	9,896
408101913	State Sales and Use Taxes	1,295	1,295	0	0
408101914	State Sales and Use Taxes	4,367	4,367	0	0
	Miscellaneous Taxes	(118,569)	(61,728)	(59,697)	2,856
	Other Non-Income Taxes	(118,569)	(61,728)	(59,697)	2,856
	Taxes Other Than Income Taxes	5,303,278	1,947,765	2,482,831	872,683
	TOTAL OPERATING EXPENSES	67,332,869	36,822,599	34,688,783	5,806,615
	Memo: SEC Total Operating Expenses	174,229,875	158,220,576	141,585,989	5,806,615
	OPERATING INCOME	58,900,575	13,750,186	27,241,140	17,909,249

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09B V2014-03-31	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consd GLS8016 Actual YTD Mar 2014	Kentucky Power Company - Distribution 110 Actual YTD Mar 2014	Kentucky Power Company - Generation 117 Actual YTD Mar 2014	Kentucky Power Company - Transmission 180 Actual YTD Mar 2014
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	3,193	4,316	(1,076)	(47)
	Interest & Dividend NonAffiliated	**3,193**	**4,316**	**(1,076)**	**(47)**
4190001	Interest Inc - Assoc Non CBP	4,025	4,025	0	0
4190005	Interest Income - Assoc CBP	9,270	1,121	(25,373)	33,523
	Interest & Dividend Affiliated	**13,295**	**5,145**	**(25,373)**	**33,523**
	Total Interest & Dividend Income	**16,488**	**9,461**	**(26,450)**	**33,476**
4210039	Carrying Charges	16,441	0	0	16,441
	Interest & Dividend Carrying Charge	**16,441**	**-**	**-**	**16,441**
	Memo: Total Interest & Dividend Income w/ Carrying	**32,928**	**9,461**	**(26,450)**	**49,917**
4191000	Allw Oth Fnds Usd Drng Cnstr	1,456,457	131,006	925,993	399,458
	AFUDC	**1,456,457**	**131,006**	**925,993**	**399,458**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
	Interest LTD IPC	**-**	**-**	**-**	**-**
4300001	Interest Exp - Assoc Non-CBP	262,500	104,341	77,222	80,937
	Interest LTD Notes Payable - Affiliated	**262,500**	**104,341**	**77,222**	**80,937**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	8,499,677	3,378,536	2,500,435	2,620,705
	Interest LTD Senior Unsecured	**8,499,677**	**3,378,536**	**2,500,435**	**2,620,705**
4270012	PCRB Interest Exp-Assoc	4,025	4,025	0	0
	Interest LTD Other - Affil	**4,025**	**4,025**	**-**	**-**
4270005	Int on LTD - Other LTD	720,139	726,736	(6,597)	0
	Interest LTD Other - NonAffil	**720,139**	**726,736**	**(6,597)**	**-**
	Interest on Long-Term Debt	**9,486,340**	**4,213,638**	**2,571,060**	**2,701,642**
4300003	Int to Assoc Co - CBP	10,270	757	74,861	(65,348)
	Interest STD - Affil	**10,270**	**757**	**74,861**	**(65,348)**
4310007	Lines Of Credit	188,674	80,840	90,353	17,481
	Interest STD - NonAffil	**188,674**	**80,840**	**90,353**	**17,481**
	Interest on Short Term Debt	**198,944**	**81,597**	**165,213**	**(47,867)**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	117,797	46,823	34,653	36,320
	Amort of Debt Disc, Prem & Exp	**117,797**	**46,823**	**34,653**	**36,320**
4281004	Amrtz Loss Rcqured Debt-Dbnt	8,412	3,757	1,806	2,850
	Amort Loss on Reacquired Debt	**8,412**	**3,757**	**1,806**	**2,850**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**
	Other Interest - Fuel Recovery	**-**	**-**	**-**	**-**
4310001	Other Interest Expense	51,706	20,228	27,152	4,326
4310002	Interest on Customer Deposits	6,989	6,989	0	0
4310023	Interest Expense - State Tax	1,095	545	523	27
	Other Interest - NonAffil	**59,790**	**27,762**	**27,675**	**4,353**
	Other Interest Expense - Affil	**-**	**-**	**-**	**-**
	Interest Rate Hedge Unrealized (Gain)/Loss	**-**	**-**	**-**	**-**
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(769,991)	(68,599)	(492,022)	(209,370)
	AFUDC-Borrowed Funds	**(769,991)**	**(68,599)**	**(492,022)**	**(209,370)**
	Total Interest Charges	**9,101,291**	**4,304,978**	**2,308,385**	**2,487,928**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**51,288,669**	**9,585,676**	**25,832,297**	**15,870,695**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	14,354,962	3,539,306	6,444,252	4,371,404
4092001	Inc Tax, Oth Inc&Ded-Federal	(181,627)	(109,640)	(59,649)	(12,338)
	Federal Current Income Tax	**14,173,335**	**3,429,666**	**6,384,603**	**4,359,066**
4101001	Prov Def I/T Utl Op Inc-Fed	17,113,377	1,726,942	14,330,081	1,056,355
4102001	Prov Def I/T Oth I&D - Federal	154,166	93,813	42,806	17,547
4111001	Prv Def I/T-Cr Utl Op Inc-Fed	(14,976,142)	(2,187,163)	(12,415,735)	(373,245)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(20,388)	0	(20,388)	0
	Federal Deferred Income Tax	**2,271,014**	**(366,407)**	**1,936,764**	**700,656**
4114001	ITC Adj, Utility Oper - Fed	(24,010)	(3,780)	(5,778)	(14,452)
	Federal Investment Tax Credits	**(24,010)**	**(3,780)**	**(5,778)**	**(14,452)**
	Federal Income Taxes	**16,420,338**	**3,059,479**	**8,315,589**	**5,045,270**
409100214	Income Taxes UOI - State	2,504,946	462,157	1,286,765	756,023
409200214	Inc Tax Oth Inc Ded - State	(31,525)	(19,030)	(10,353)	(2,142)
	State Current Income Tax	**2,473,421**	**443,127**	**1,276,412**	**753,882**
4111002	Prv Def I/T-Cr UtlOpInc-State	(152,880)	0	(152,880)	0
	State Deferred Income Tax	**(152,880)**	**-**	**(152,880)**	**-**
	State Investment Tax Credits	**-**	**-**	**-**	**-**
	State Income Taxes	**2,320,541**	**443,127**	**1,123,532**	**753,882**
	Local Current Income Tax	**-**	**-**	**-**	**-**

American Electric Power

GLS8016
YTD Mar 2014
04/07/2014 18:05

INCOME STATEMENT

Layout: GLS8016

09B V2014-03-31 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8016 Actual YTD Mar 2014	Kentucky Power Company - Distribution 110 Actual YTD Mar 2014	Kentucky Power Company - Generation 117 Actual YTD Mar 2014	Kentucky Power Company - Transmission 180 Actual YTD Mar 2014
Local Deferred Income Tax	-	-	-	-
Local Investment Tax Credits	-	-	-	-
Local Income Taxes	-	-	-	-
Foreign Current Income Tax	-	-	-	-
Foreign Deferred Income Tax	-	-	-	-
Foreign Investment Tax Credits	-	-	-	-
Foreign Income Taxes	-	-	-	-
Total Income Taxes	18,740,879	3,502,606	9,439,121	5,799,152
Equity Earnings of Subs	-	-	-	-
INCOME AFTER INCOME TAXES and EQUITY EARNINGS	32,547,790	6,083,070	16,393,176	10,071,543
Discontinued Operations (Net of Taxes)	-	-	-	-
Cumulative Effect of Accounting Changes	-	-	-	-
Extraordinary Income / (Expenses)	-	-	-	-
NET INCOME	32,547,790	6,083,070	16,393,176	10,071,543
Minority Interest	-	-	-	-
Preferred Stock Dividend Subs	-	-	-	-
Earnings to Common Shareholders	32,547,790	6,083,070	16,393,176	10,071,543
NET INCOME (LOSS) NODE before PS	32,547,790	6,083,070	16,393,176	10,071,543
Double Check on Net Income Node after PS	-	(0)	(0)	-

Reserved Section

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Mar 2014
04/08/2014 12:52

Layout : GLS8216

09B V2014-03- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Mar 2014	YTD Mar 2014	YTD Mar 2014	YTD Mar 2014
ASSETS				
Cash and Cash Equivalents	1,243,785	1,243,785	0	0
Other Cash Deposits	0	0	0	0
Customers	11,974,102	4,488,273	6,798,084	687,745
Accrued Unbilled Revenues	11,619	11,619	0	0
Miscellaneous Accounts Receivable	28,386,520	6,500,194	68,357,215	8,443,367
Allowances for Uncollectible Accounts	(62,619)	(50,992)	(11,628)	0
Accounts Receivable	40,309,623	10,949,095	75,143,672	9,131,112
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	86,574,062	2,599,148	83,077,591	897,322
Risk Management Contracts - Current	4,276,813	14,088	4,262,725	0
Margin Deposits	2,364,251	17,341	2,346,909	0
Unrecovered Fuel - Current	10,593,646	0	10,593,646	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	3,231,891	2,794,519	336,436	100,936
TOTAL CURRENT ASSETS	148,594,070	17,617,977	175,760,979	10,129,371
Electric Production	1,063,586,483	742,827,851	1,495,184,137	507,408,292
Electric Transmission	510,961,565	0	0	0
Electric Distribution	698,685,338	0	0	0
General Property, Plant and Equipment	477,716,350	199,571	4,169,386	1,160,479
Construction Work-in-Progress	139,320,820	15,480,023	85,725,645	38,115,151
TOTAL PROPERTY, PLANT and EQUIPMENT	2,890,270,535	758,507,445	1,585,079,168	546,683,922
less: Accumulated Depreciation and Amortization	(962,784,858)	(236,221,890)	(558,671,058)	(167,891,910)
NET PROPERTY, PLANT and EQUIPMENT	1,927,485,677	522,285,555	1,026,408,110	378,792,012
Net Regulatory Assets	214,764,773	102,706,513	56,435,208	55,623,052
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	2,880,433	0	2,880,433	0
Employee Benefits and Pension Assets	13,804,334	(1,001,421)	14,495,630	310,125
Other Non Current Assets	14,612,177	5,988,477	5,520,971	3,102,730
TOTAL OTHER NON-CURRENT ASSETS	246,061,718	107,693,569	79,332,242	59,035,907
TOTAL ASSETS	2,322,141,465	647,597,100	1,281,501,330	447,957,290
LIABILITIES				
Accounts Payable	68,640,709	62,857,638	57,069,657	3,627,671
Advances from Affiliates	49,404,058	(7,307,715)	184,024,952	(127,313,180)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	0	0	0	0
Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
Risk Management Liabilities	905,269	0	905,269	0
Accrued Taxes	26,181,532	8,906,434	5,288,158	11,986,940

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Mar 2014
04/08/2014 12:52

Layout : GLS8216

09B V2014-03-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Mar 2014	Kentucky Power Company - 110 YTD Mar 2014	Kentucky Power Company - Generation 117 YTD Mar 2014	Kentucky Power Company - 180 YTD Mar 2014
	Memo: Property Taxes	13,752,995	6,242,232	3,671,765	3,838,998
	Accrued Interest	**5,639,612**	**2,222,536**	**1,709,003**	**1,708,073**
	Risk Management Collateral	693,570	0	693,570	0
	Utility Customer Deposits	24,595,002	24,595,002	0	0
	Deposits - Customer and Collateral	**25,288,572**	**24,595,002**	**693,570**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	1,019,615	492,593	379,982	147,040
	Tax Collections Payable	2,711,942	2,476,239	228,222	7,481
	Revenue Refunds - Accrued	1,378,946	0	259,350	1,119,596
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,898,759	723,224	1,085,294	90,240
	Accrued Rents	1,222	1,222	0	0
	Accrued ICP	1,876,959	789,133	1,021,781	66,046
	Accrued Vacations	5,684,268	2,213,008	3,204,679	266,581
	Misc Employee Benefits	1,356,641	463,530	876,626	16,484
	Payroll Deductions	223,857	98,693	110,732	14,432
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	755,574	315,942	400,180	39,452
2530022	Customer Advance Receipts	1,116,519	1,116,519	0	0
	Customer Advance	1,116,519	1,116,519	0	0
2420511	Control Cash Disburse Account	797,341	797,341	0	0
	Control Cash Disbursement Account	797,341	797,341	0	0
	JMG Liability	0	0	0	0
2420088	Econ. Development Fund Curr	291,250	0	291,250	0
2420512	Unclaimed Funds	4,371	4,371	0	0
2420542	Acc Cash Franchise Req	93,842	93,842	0	0
242059214	Sales Use Tax - Lease Equip	590	104	411	75
2420643	Accrued Audit Fees	118,376	30,912	68,066	19,398
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	246,141	0	246,141	0
2530050	Deferred Rev -Pole Attachments	196,118	196,118	0	0
2530112	Other Deferred Credits-Curr	269,175	47,559	221,616	0
2530124	Contr In Aid of Constr Advance	85,471	85,471	0	0
	Misc Current and Accrued Liabilities	1,859,660	458,378	1,381,810	19,473
	Current Other and Accrued Liabilities	19,661,689	9,453,229	8,568,676	1,639,785
	Other Current Liabilities	**20,681,304**	**9,945,822**	**8,948,658**	**1,786,824**
	TOTAL CURRENT LIABILITIES	**196,741,056**	**101,219,716**	**258,639,268**	**(108,203,671)**
	Long-Term Debt - Affiliated	**20,000,000**	**7,949,800**	**5,883,600**	**6,166,600**
	Long-Term Debt - Non Affiliated	**730,000,000**	**210,669,700**	**355,915,400**	**163,414,900**
	Long-Term Debt - Premiums and Discounts Unamort	(569,644)	(226,428)	(167,578)	(175,638)
	Memo - LTD NonAffiliated and Premiums	*729,430,356*	*210,443,272*	*355,747,822*	*163,239,262*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	1,702,636	0	1,702,636	0
2440022	L/T Liability MTM Collateral	(72,795)	0	(72,795)	0
	Long-Term Risk Management Liabilities - MTM	1,629,841	0	1,629,841	0

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Mar 2014
04/08/2014 12 52

Layout : GLS8216

09B V2014-03-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Mar 2014	Kentucky Power Company - 110 YTD Mar 2014	Kentucky Power Company - Generation 117 YTD Mar 2014	Kentucky Power Company - 180 YTD Mar 2014
	Long-Term Risk Management Liabilities	**1,629,841**	**0**	**1,629,841**	**0**
	Deferred Income Taxes	**556,398,574**	**168,270,620**	**269,533,856**	**118,594,097**
	Deferred Investment Tax Credits	**101,737**	**20,385**	**32,050**	**49,303**
	Regulatory Liabilities and Deferred Credits	**24,388,154**	(31,327,667)	**62,005,705**	(6,289,884)
	Memo - Reg Liab and Def ITC	*24,489,891*	*(31,307,282)*	*62,037,755*	*(6,240,582)*
	Asset Retirement Obligation	**20,588,300**	**61,824**	**20,526,476**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,754,111**	**3,046,042**	**4,606,924**	**101,145**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Rede	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	3,249,620	1,288,271	1,488,252	473,098
	Def Credits - Income Tax	681,409	361,821	277,000	42,588
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	113,681	113,681	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	6,303	0	6,303	0
2530067	IPP - System Upgrade Credits	270,997	0	0	270,997
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	155,314	155,314	0	0
2530101	MACSS Unidentified EDI Cash	463	463	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	99,785	0	0	99,785
	Def Credits - Other	532,861	155,777	6,303	370,782
	Total Other Deferred Credits	646,543	269,458	6,303	370,782
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	873,750	0	873,750	0
	Other Non-Current Liabilities	**6,561,965**	**1,919,550**	**3,755,948**	**886,467**
	TOTAL NON-CURRENT LIABILITIES	**1,366,853,039**	**360,383,827**	**723,722,223**	**282,746,989**
	TOTAL LIABILITIES	**1,563,594,095**	**461,603,543**	**982,361,490**	**174,543,318**
	Cumulative Pref Stocks of Subs - Not subject Mand Reden	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**517,459,453**	**106,025,371**	**327,394,246**	**84,039,836**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**197,238,714**	**57,646,194**	(32,086,922)	**171,679,441**
	Accumulated Other Comprehensive Income (Loss)	(6,600,797)	(82,058)	(6,455,087)	(63,652)
	TOTAL SHAREHOLDERS' EQUITY	**758,547,370**	**185,993,557**	**299,139,840**	**273,413,973**
	Memo: Total Equity	758,547,370	185,993,557	299,139,840	273,413,973
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**2,322,141,465**	**647,597,100**	**1,281,501,330**	**447,957,290**
	out-of-balance	(0)	0	0	(0)

Reserved Section

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AMERICAN ELECTRIC POWER COMPANY
GLA8216N

BALANCE SHEET

YTD Mar 2013
04/08/2013 14:22

Layout : GLA8216V

09B V2099-01 Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLA8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Mar 2013	YTD Mar 2013	YTD Mar 2013	YTD Mar 2013
ASSETS				
Cash and Cash Equivalents	861,534	861,534	0	0
Other Cash Deposits	0	0	0	0
Customers	18,630,358	13,482,971	4,091,752	1,055,635
Accrued Unbilled Revenues	1,794,374	1,794,374	0	0
Miscellaneous Accounts Receivable	5,402,807	2,743,314	44,873,562	7,957,707
Allowances for Uncollectible Accounts	(9,818)	(9,818)	0	0
Accounts Receivable	25,817,721	18,010,841	48,965,314	9,013,342
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	69,594,047	2,359,582	66,420,635	813,829
Risk Management Contracts - Current	4,621,886	28,542	4,593,344	0
Margin Deposits	1,816,791	28,871	1,787,920	0
Unrecovered Fuel - Current	16,631	0	16,631	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	3,718,900	1,352,492	2,259,306	107,103
TOTAL CURRENT ASSETS	106,447,510	22,641,862	124,043,149	9,934,275
Electric Production	560,292,077	709,207,245	569,045,511	495,293,305
Electric Transmission	490,860,564	0	0	0
Electric Distribution	663,709,980	0	0	0
General Property, Plant and Equipment	64,382,944	199,571	4,370,046	1,129,887
Construction Work-in-Progress	43,807,564	13,623,984	1,912,755	28,270,825
TOTAL PROPERTY, PLANT and EQUIPMENT	1,823,053,129	723,030,800	575,328,312	524,694,018
less: Accumulated Depreciation and Amortization	(613,218,731)	(220,921,170)	(229,273,575)	(163,023,987)
NET PROPERTY, PLANT and EQUIPMENT	1,209,834,398	502,109,630	346,054,737	361,670,031
Net Regulatory Assets	214,240,206	121,930,061	36,139,413	56,170,732
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	4,948,523	1,863	4,946,660	0
Employee Benefits and Pension Assets	0	0	0	0
Other Non Current Assets	45,536,568	4,964,041	37,909,133	2,663,394
TOTAL OTHER NON-CURRENT ASSETS	264,725,297	126,895,966	78,995,206	58,834,125
TOTAL ASSETS	1,581,007,205	651,647,458	549,093,092	430,438,431
LIABILITIES				
Accounts Payable	39,974,193	57,310,545	28,988,274	3,847,150
Advances from Affiliates	11,039,250	7,690,423	118,489,582	(115,140,755)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	0	0	0	0
Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
Risk Management Liabilities	2,379,578	0	2,379,578	0
Accrued Taxes	8,009,392	5,062,148	(4,092,274)	7,039,519

AMERICAN ELECTRIC POWER COMPANY
GLA8216N

BALANCE SHEET

YTD Mar 2013
04/08/2013 14:22

Layout : GLA8216V

09B V2099-01-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLA8216 YTD Mar 2013	Kentucky Power Company - 110 YTD Mar 2013	Kentucky Power Company - Generation 117 YTD Mar 2013	Kentucky Power Company 180 YTD Mar 2013
	Memo: Property Taxes	10,711,355	4,354,858	3,160,148	3,196,349
	Accrued Interest	**5,575,175**	**2,250,925**	**1,546,819**	**1,777,431**
	Risk Management Collateral	146,524	0	146,524	0
	Utility Customer Deposits	23,811,141	23,811,141	0	0
	Deposits - Customer and Collateral	**23,957,664**	**23,811,141**	**146,524**	**0**
	Over-Recovered Fuel Costs - Current	**0**	**0**	**0**	**0**
	Dividends Declared	0	0	0	0
	Preferred Stock due W/IN 1 Yr	0	0	0	0
	Obligations under Capital Leases - Current	1,351,691	875,208	243,021	233,462
	Tax Collections Payable	2,105,238	2,068,130	26,974	10,135
	Revenue Refunds - Accrued	3,704,805	1,635,430	14,537	2,054,838
	Accrued Rents - Rockport	0	0	0	0
	Accrued - Payroll	1,005,113	623,881	273,146	108,086
	Accrued Rents	1,418	1,418	0	0
	Accrued ICP	596,381	406,758	134,344	55,280
	Accrued Vacations	3,504,660	2,128,390	1,003,130	373,141
	Misc Employee Benefits	1,998,361	1,029,209	827,794	141,358
	Payroll Deductions	147,697	86,868	43,522	17,307
	Severance / SEI	1,425	1,425	0	0
	Accrued Workers Compensation	461,334	332,154	108,672	20,508
2530022	Customer Advance Receipts	1,851,235	1,851,235	0	0
	Customer Advance	1,851,235	1,851,235	0	0
	Control Cash Disbursement Account	401,529	401,529	0	0
	JMG Liability	0	0	0	0
2420512	Unclaimed Funds	3,657	3,657	0	0
2420542	Acc Cash Franchise Req	100,235	100,235	0	0
242059213	Sales Use Tax - Lease Equip	4,540	1,155	145	3,240
2420643	Accrued Audit Fees	84,761	37,045	25,216	22,500
2420656	Federal Mitigation Accru (NSR)	376,794	0	376,794	0
2420664	ST State Mitigation Def (NSR)	424,404	0	424,404	0
2530050	Deferred Rev -Pole Attachments	202,084	202,084	0	0
2530112	Other Deferred Credits-Curr	1,014,651	26,678	987,973	0
	Misc Current and Accrued Liabilities	2,211,125	370,854	1,814,532	25,739
	Current Other and Accrued Liabilities	17,990,321	10,937,280	4,246,649	2,806,392
	Other Current Liabilities	**19,342,012**	**11,812,488**	**4,489,671**	**3,039,853**
	TOTAL CURRENT LIABILITIES	**110,277,264**	**107,937,669**	**151,948,173**	**(99,436,802)**
	Long-Term Debt - Affiliated	**20,000,000**	**6,907,200**	**7,335,600**	**5,757,200**
	Long-Term Debt - Non Affiliated	**530,000,000**	**197,753,600**	**176,839,800**	**155,406,600**
	Long-Term Debt - Premiums and Discounts Unamort	(736,369)	(274,754)	(245,697)	(215,918)
	Memo - LTD NonAffiliated and Premiums	*529,263,631*	*197,478,846*	*176,594,103*	*155,190,682*
	Long-Term Risk Management Liabilities - Hedge	23,297	778	22,519	0
2440002	LT Unreal Losses - Non Affil	2,767,872	0	2,767,872	0
2440022	L/T Liability MTM Collateral	(161,089)	(595)	(160,494)	0
	Long-Term Risk Management Liabilities - MTM	2,606,783	(595)	2,607,378	0
	Long-Term Risk Management Liabilities	**2,630,080**	**183**	**2,629,897**	**0**
	Deferred Income Taxes	**362,229,217**	**160,474,861**	**92,609,068**	**109,145,288**
	Deferred Investment Tax Credits	**298,257**	**53,227**	**76,155**	**168,874**

AMERICAN ELECTRIC POWER COMPANY
GLA8216N

BALANCE SHEET

YTD Mar 2013
04/08/2013 14:22

Layout : GLA8216V

09B V2099-01-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLA8216 YTD Mar 2013	Kentucky Power Company - 110 YTD Mar 2013	Kentucky Power Company - Generation 117 YTD Mar 2013	Kentucky Power Company - 180 YTD Mar 2013
	Regulatory Liabilities and Deferred Credits	**25,258,403**	(27,606,403)	**58,126,196**	(5,261,390)
	Memo - Reg Liab and Def ITC	*25,556,659*	*(27,553,176)*	*58,202,351*	*(5,092,516)*
	Asset Retirement Obligation	**3,980,233**	**58,378**	**3,921,855**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**32,124,128**	**19,485,248**	**10,854,561**	**1,784,319**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Rede	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	1,965,664	954,667	689,594	321,404
	Def Credits - Income Tax	1,290,529	372,236	878,685	39,609
2530114	Federl Mitigation Deferal(NSR)	754,942	0	754,942	0
	Def Credits - NSR	754,942	0	754,942	0
2520000	Customer Adv for Construction	57,952	57,952	0	0
	Customer Advances for Construction	57,952	57,952	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530044	Neigh Help Neig-Cust Donations	(222)	(222)	0	0
2530067	IPP - System Upgrade Credits	262,366	0	0	262,366
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	161,198	161,198	0	0
2530101	MACSS Unidentified EDI Cash	218	218	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	113,340	0	0	113,340
	Def Credits - Other	536,900	161,194	0	375,706
	Total Other Deferred Credits	594,852	219,146	0	375,706
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	0	0	0	0
	Other Non-Current Liabilities	**4,605,987**	**1,546,049**	**2,323,220**	**736,718**
	TOTAL NON-CURRENT LIABILITIES	**980,389,936**	**358,397,589**	**354,470,656**	**267,521,691**
	TOTAL LIABILITIES	**1,090,667,201**	**466,335,258**	**506,418,829**	**168,084,890**
	Cumulative Pref Stocks of Subs - Not subject Mand Reden	**0**	**0**	**0**	**0**
	Minority Interest - Deferred Credits	**0**	**0**	**0**	**0**
	COMMON SHAREHOLDERS' EQUITY				
	Common Stock	**50,450,000**	**22,404,049**	**10,287,603**	**17,758,348**
	Paid In Capital	**238,750,000**	**106,025,371**	**48,684,793**	**84,039,836**
	Premium on Capital Stock	**0**	**0**	**0**	**0**
	Retained Earnings	**201,330,503**	**56,952,758**	(16,257,254)	**160,634,998**
	Accumulated Other Comprehensive Income (Loss)	(190,499)	(69,979)	(40,879)	(79,641)
	TOTAL SHAREHOLDERS' EQUITY	**490,340,004**	**185,312,200**	**42,674,263**	**262,353,541**
	Memo: Total Equity	490,340,004	185,312,200	42,674,263	262,353,541
	TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	**1,581,007,205**	**651,647,458**	**549,093,092**	**430,438,431**
	out-of-balance	(0)	0	0	(0)

Reserved Section

Final 04/08/2014

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - March, 2014

GLR7210V 04/08/14 14:21

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	8,705,144.32	(1,631,936.20)	(9.12)	0.00	1,485,757,450.88
	TOTAL PRODUCTION	**1,478,684,251.88**	**8,705,144.32**	**(1,631,936.20)**	**(9.12)**	**0.00**	**1,485,757,450.88**
101/106	TRANSMISSION	503,165,571.80	3,515,083.68	(58,932.75)	0.00	0.00	506,621,722.73
101/106	DISTRIBUTION	733,776,590.81	7,744,460.95	(1,898,103.37)	0.00	0.00	739,622,948.39
	TOTAL (ACCOUNTS 101 & 106)	**2,715,626,414.49**	**19,964,688.95**	**(3,588,972.32)**	**(9.12)**	**0.00**	**2,732,002,122.00**
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	(266,950.05)	0.00	6,012,199.12
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**2,721,905,563.66**	**19,964,688.95**	**(3,588,972.32)**	**(266,959.17)**	**0.00**	**2,738,014,321.12**
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		30,686,360.34				
107000X	TRANSFERS		(19,964,688.95)				
107000X	END. BAL.		10,721,671.39				139,320,819.58
	TOTAL ELECTRIC UTILITY PLANT	**2,857,910,670.58**	**30,686,360.34**	**(3,588,972.32)**	**(266,959.17)**	**0.00**	**2,884,741,099.43**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	**5,529,435.74**	**0.00**	**0.00**	**(0.03)**	**0.00**	**5,529,435.71**

Prepared by: PSnVision Report GLS7210V
Reviewer: Cindy Buckbee -- Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

Final 04/08/2014

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - March, 2014

GLR7410V 04/08/14 14:22

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	14,141,200.00	(1,631,936.20)	(151,958.04)	0.00	611,861,432.65
1080001/11	TRANSMISSION	161,537,795.16	2,178,609.87	(58,932.75)	(88,130.02)	0.00	163,569,342.26
1080001/11	DISTRIBUTION	192,744,660.64	6,322,399.61	(1,698,103.37)	(414,580.41)	0.00	196,754,376.67
1080013	PRODUCTION	(3,620,015.26)	0.00	0.00	0.00	(132,039.96)	(3,752,055.22)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698.85)	0.00	0.00	0.00	(2,288.35)	(28,987.20)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(1,187,451.82)	654,668.47	(8,853,035.87)
	TOTAL (108X accounts)	**941,819,616.07**	**22,642,209.68**	**(3,388,972.32)**	**(1,842,120.29)**	**520,340.16**	**959,551,073.30**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	329,535.68	0.00	0.00	84,795.27	10,843,681.82
1110001	TRANSMISSION	1,607,792.68	142,198.12	0.00	0.00	0.00	1,749,990.80
1110001	DISTRIBUTION	7,182,584.75	374,804.98	0.00	0.00	0.00	7,557,389.73
	TOTAL (111X accounts)	**19,219,728.30**	**846,538.78**	**0.00**	**0.00**	**84,795.27**	**20,151,062.35**
1011006	CAPITAL LEASES	1,869,467.09	0.00	0.00	0.00	(126,503.29)	1,742,963.80
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**962,908,811.46**	**23,488,748.46**	**(3,388,972.32)**	**(1,842,120.29)**	**478,632.14**	**981,445,099.45**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	214,955.75	1,667.43	0.00	0.00	0.00	216,623.18
1240027	Other Property - RWIP	(3,400.00)	0.00	0.00	0.00	0.00	(3,400.00)
	TOTAL NONUTILITY PLANT	**211,555.75**	**1,667.43**	**0.00**	**0.00**	**0.00**	**213,223.18**

Prepared By: PSnVision Report GLS7410V
Reviewer: Cindy Buckbee – Prop Acctg. Canton
Sources of Info: PowerPlant Reports and PS GL

AEP
AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

May 29, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed April 2014 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-9	Income Statement
1-3	Details of Operating Revenues
4-7	Operating Expenses – Functional Expenses
8-9	Detail Statement of Taxes

Balance Sheet:

10	Balance Sheet – Assets & Other Debits
10-12	Balance Sheet – Liabilities & Other Credits
11-12	Deferred Credits
12	Statement of Retained Earnings

Utility Property:

13-14	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz
Manager –Regulated Accounting

American Electric Power

INCOME STATEMENT

GLS8016
YTD Apr 2014
05/08/2014 18:37

Layout: GLS8016
09B V2014-04-30 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Apr 2014	Kentucky Power Company - Distribution 110 Actual YTD Apr 2014	Kentucky Power Company - Generation 117 Actual YTD Apr 2014	Kentucky Power Company - Transmission 180 Actual YTD Apr 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	53,294,054	49,838,648	3,455,406	0
4400002		Residential Sales-W/O Space Ht	17,054,928	19,084,381	(2,029,453)	0
4400005		Residential Fuel Rev	29,373,621	29,373,621	0	0
	A	**Revenue - Residential Sales**	**99,722,603**	**98,296,650**	**1,425,953**	-
4420001		Commercial Sales	25,329,776	25,592,540	(262,764)	0
4420006		Sales to Pub Auth - Schools	4,737,243	4,787,291	(50,048)	0
4420007		Sales to Pub Auth - Ex Schools	4,604,306	4,725,534	(121,228)	0
4420013		Commercial Fuel Rev	13,602,898	13,602,898	0	0
	A	**Revenue - Commercial Sales**	**48,274,223**	**48,708,263**	**(434,040)**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	20,763,039	20,930,420	(167,381)	0
4420004		Ind Sales-NonAffil(incl Mines)	10,050,397	10,142,740	(92,343)	0
4420016		Industrial Fuel Rev	28,126,735	28,126,735	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**58,940,172**	**59,199,896**	**(259,724)**	-
		Revenue - Industrial Sales	**58,940,172**	**59,199,896**	**(259,724)**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	476,714	479,368	(2,655)	0
4440002		Public St & Hwy Light Fuel Rev	111,308	111,308	0	0
	A	**Revenue - Other Retail Sales**	**588,022**	**590,677**	**(2,655)**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**207,525,019**	**206,795,485**	**729,534**	-
4560043		Oth Elec Rv Trn-Aff-Trnf Price	0	0	0	12,121,705
4561033		PJM NITS Revenue - Affiliated	5,927,747	0	0	12,026,450
4561034		PJM TO Adm. Serv Rev - Aff	0	0	0	198,511
4561035		PJM Affiliated Trans NITS Cost	(5,910,528)	0	(12,009,231)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(198,511)	0
4561059		Affil PJM Trans Enhancmnt Rev	54,482	0	0	108,700
4561060		Affil PJM Trans Enhancmnt Cost	(54,328)	0	(108,545)	0
4561062		PROVISION PJM NITS Affil- Cost	(254,693)	0	(254,693)	0
4561063		PROVISION PJM NITS Affiliated	(73,822)	0	0	(73,822)
	B	**Revenue - Transmission-Affiliated**	**(311,141)**	-	**(12,570,980)**	**24,381,543**
4470150		Transm. Rev -Dedic. Whls/Muni	18,502	0	(222,664)	241,167
4470206		PJM Trans loss credits-OSS	978,062	0	978,062	0
4470207		PJM transm loss charges - LSE	(10,731,104)	0	(10,731,104)	0
4470208		PJM Transm loss credits-LSE	1,718,836	0	1,718,836	0
4470209		PJM transm loss charges-OSS	(7,530,078)	0	(7,530,078)	0
4561002		RTO Formation Cost Recovery	1,224	0	(46,916)	48,140
4561003		PJM Expansion Cost Recov	26,914	0	(29,396)	56,310
4561005		PJM Point to Point Trans Svc	255,282	0	255,282	0
4561006		PJM Trans Owner Admin Rev	91,257	0	0	91,257
4561007		PJM Network Integ Trans Svc	4,782,661	0	0	4,782,661
4561019		Oth Elec Rev Trans Non Affil	22,475	0	0	22,475
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	1,362	0	0	1,362
4561029		PJM NITS Revenue Whsl Cus-NAff	892,980	0	0	892,980
4561030		PJM TO Serv Rev Whls Cus-NAff	13,647	0	0	13,647
4561058		NonAffil PJM Trans Enhncmt Rev	111,546	0	0	111,546
4561061		NAff PJM RTEP Rev for Whsl-FR	8,071	0	0	8,071
4561064		PROVISION PJM NITS WhslCus-NAf	(4,477)	0	0	(4,477)
4561065		PROVISION PJM NITS	(26,663)	0	0	(26,663)
	A	**Revenue - Transmission-NonAffiliated**	**(9,369,503)**	-	**(15,607,976)**	**6,238,474**
		Revenue - Transmission	**(9,680,644)**	-	**(28,178,956)**	**30,620,017**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	262	0	262	0
4470128		Sales for Res-Aff Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,479,520**	-	**5,479,520**	-
4470002		Sales for Resale - NonAssoc	3,131	0	3,131	0
4470006		Sales for Resale-Bookout Sales	6,499,835	0	6,499,835	0
4470010		Sales for Resale-Bookout Purch	(7,857,274)	0	(7,857,274)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,022,631	0	1,022,631	0
4470028		Sale/Resale - NA - Fuel Rev	178,509	0	178,509	0
4470033		Whsal/Muni/Pub Auth Base Rev	913,618	0	913,618	0
4470066		PWR Trdng Trans Exp-NonAssoc	(39)	0	(39)	0
4470081		Financial Spark Gas - Realized	11,003	0	11,003	0
4470082		Financial Electric Realized	2,471,772	0	2,471,772	0
4470089		PJM Energy Sales Margin	73,282,344	0	73,282,344	0
4470093		PJM Implicit Congestion-LSE	(19,442,705)	0	(19,442,705)	0
4470098		PJM Oper Reserve Rev-OSS	(2,557,912)	0	(2,557,912)	0
4470099		Capacity Cr. Net Sales	166,556	0	166,556	0
4470100		PJM FTR Revenue-OSS	571,255	0	571,255	0
4470101		PJM FTR Revenue-LSE	6,780,667	0	6,780,667	0
4470103		PJM Energy Sales Cost	63,984,056	0	63,984,056	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Apr 2014
05/08/2014 16:37

Layout: GLS8016
098 V2014-04-30 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Apr 2014	Kentucky Power Company - Distribution 110 Actual YTD Apr 2014	Kentucky Power Company - Generation 117 Actual YTD Apr 2014	Kentucky Power Company - Transmission 180 Actual YTD Apr 2014
4470106		PJM Pt2Pt Trans Purch-NonAff	(27)	0	(27)	0
4470107		PJM NITS Purch-NonAff	22,881	0	22,881	0
4470109		PJM FTR Revenue-Spec	(81,232)	0	(81,232)	0
4470110		PJM TO Admin. Exp.-NonAff	34,729	0	34,729	0
4470112		Non-Trading Bookout Sales-OSS	4,943	0	4,943	0
4470115		PJM Meter Corrections-OSS	(12,662)	0	(12,662)	0
4470116		PJM Meter Corrections-LSE	38,505	0	38,505	0
4470124		PJM Incremental Spot-OSS	1	0	1	0
4470126		PJM Incremental Imp Cong-OSS	(18,934,829)	0	(18,934,829)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	(224,185)	0	(224,185)	0
4470144		Realz Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim. Margin Reclass	(175)	0	(175)	0
4470168		Interest Rate Swaps-Power	(3,285)	0	(3,285)	0
4470170		Non-ECR Auction Sales-OSS	1,164,102	0	1,164,102	0
4470174		PJM Whlse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	179,313	0	179,313	0
4470176		OSS Sharing Reclass-Reduction	(179,313)	0	(179,313)	0
4470180		Trading intra-book Reclass	(149,091)	0	(149,091)	0
4470181		Auction intra-book Reclass	149,091	0	149,091	0
4470202		PJM OpRes-LSE-Credit	919,021	0	919,021	0
4470203		PJM OpRes-LSE-Charge	(4,362,996)	0	(4,362,996)	0
4470204		PJM Spinning-Credit	(0)	0	(0)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,180	0	28,180	0
4470220		PJM Regulation - OSS	97,425	0	97,425	0
4470221		PJM Spinning Reserve - OSS	8,974	0	8,974	0
4470222		PJM Reactive - OSS	210,996	0	210,996	0
4560016		Financial Trading Rev-Unreal	(212)	(212)	0	0
4560050		Oth Elec Rev Coal Trd Rlzd G-L	(10,423)	0	(10,423)	0
5550080		PJM Hourly Net Purch -FERC	(15,084,962)	0	(15,084,962)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**89,843,831**	**(212)**	**89,844,043**	-
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**95,323,351**	**(212)**	**95,323,563**	-
4470074		Sale for Resale-Aff-Trnf Price	0	0	151,982,444	0
4540001		Rent From Elect Property - Af	103,787	314,527	0	0
4560001		Oth Elect Rev - Affiliated	4,906	0	4,906	0
	B	**Revenue - Other Ele-Affiliated**	**108,693**	**314,527**	**151,987,350**	-
4500000		Forfeited Discounts	1,534,126	1,534,126	0	0
4510001		Misc Service Rev - Nonaffil	113,591	109,072	0	4,519
4540002		Rent From Elect Property-NAC	59,364	600	56,989	1,775
4540005		Rent from Elec Prop-Pole Attch	1,639,078	1,639,078	0	0
4560007		Oth Elect Rev - DSM Program	2,236,994	2,236,994	0	0
		Revenue - Other Ele-NonAffiliated	**5,583,152**	**5,519,870**	**56,989**	**6,294**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	383	0	383	0
4118004		Comp. Allow. Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,916**	-	**8,916**	-
	A	**Revenue - Other Ele-NonAffiliated**	**5,592,068**	**5,519,870**	**65,905**	**6,294**
		Revenue - Other Opr Electric	**5,700,762**	**5,834,397**	**152,053,255**	**6,294**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliatec**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliatec**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operating Rental Income	11,400	11,000	400	0
4180003		Non Opratng Rntal Inc-Maint	(16)	0	(16)	0
4180005		Non-Opratng Rntal Inc-Depr	(2,223)	0	0	(2,223)
	D	**Non-Operating Rental Income - NonAffiliatec**	**9,161**	**11,000**	**384**	**(2,223)**
		Non-Operating Rental Income	**9,161**	**11,000**	**384**	**(2,223)**
	C	**Non-Operating Misc Income -Affiliatec**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	2,059	236	1,675	148
4210007		Misc Non-Op Inc - NonAsc - Oth	346	259	87	0
	D	**Non-Operating Misc Income - NonAffiliatec**	**2,405**	**495**	**1,762**	**148**
		Non-Operating Misc Income	**2,405**	**495**	**1,762**	**148**
4540004		Rent From Elect Prop-ABD-Nonaf	28,046	28,046	0	0
4560015		Other Electric Revenues - ABD	81,895	82,443	0	(548)
	D	**Associated Business Development Income**	**109,940**	**110,488**	-	**(548)**
		Revenue - Other Opr - Other	**121,506**	**121,983**	**2,146**	**(2,623)**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***121,506***	***121,983***	***2,146***	***(2,623)***

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		Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
		GLS8016	110	117	180
		Actual	Actual	Actual	Actual
098 V2014-04-30	Layout: GLS8016 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	YTD Apr 2014	YTD Apr 2014	YTD Apr 2014	YTD Apr 2014
	Revenue - Other Operating	5,822,268	5,956,380	152,055,401	3,670
A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
B	**Provision for Rate Refund - Affiliated**	-	-	-	-
	Provision for Rate Refund	-	-	-	-
4210031	Pwr Sales Outside Svc Territy	1,561	0	1,561	0
4210032	Pwr Purch Outside Svc Territy	(258)	0	(258)	0
A	**Revenue - Power Sales**	1,304	-	1,304	-
	TOTAL OPERATING REVENUES	298,991,298	212,751,654	219,930,845	30,623,687
=(A)	*Memo: G/T/D Revenue*	293,592,720	212,315,143	75,032,809	6,244,767
=(B)	*Memo: Other Affiliated Revenue*	5,277,072	314,527	144,895,890	24,381,543
=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth Non*	121,506	121,983	2,146	(2,623)
	Memo: Total Operating Revenues	298,991,298	212,751,654	219,930,845	30,623,687
=(E)=(B)+(C)	*Memo: Affiliated Revenue*	5,277,072	314,527	144,895,890	24,381,543
=(F)=(D)+(A)	*Memo: Non-Affiliated Revenue*	283,714,226	212,437,126	75,034,955	6,242,144
	Memo: Total Operating Revenues	298,991,298	212,751,654	219,930,845	30,623,687
	FUEL EXPENSES				
5010000	Fuel	51,063	0	51,063	0
5010001	Fuel Consumed	99,809,554	0	99,809,554	0
5010003	Fuel - Procure Unload & Handle	4,606,432	0	4,606,432	0
5010013	Fuel Survey Activity	(734,602)	0	(734,602)	0
5010019	Fuel Oil Consumed	2,440,553	0	2,440,553	0
5010027	Gypsum handling/disposal costs	107,025	0	107,025	0
5010028	Gypsum Sales Proceeds	(294,453)	0	(294,453)	0
	Fuel Expense Total	105,985,571	-	105,985,571	-
5010005	Fuel - Deferred	(14,037,226)	0	(14,037,226)	0
	Deferred Fuel Expense	(14,037,226)	-	(14,037,226)	-
	Over Under Fuel Expense				
	Fuel for Electric Generation	91,948,345	-	91,948,345	-
5010029	Gypsum handling/displ-Affiliat	52,769	0	52,769	0
	Fuel from Affiliates for Electric Generation	52,769	-	52,769	-
5090000	Allow Consum Title IV SO2	3,337,873	0	3,337,873	0
5090005	An. NOx Cons. Exp	51,482	0	51,482	0
	Allowances - Consumption	3,389,355	-	3,389,355	-
5020002	Urea Expense	1,816,498	0	1,816,498	0
5020003	Trona Expense	123,085	0	123,085	0
5020004	Limestone Expense	1,461,747	0	1,461,747	0
5020005	Polymer expense	27,579	0	27,579	0
5020007	Lime Hydrate Expense	2,923	0	2,923	0
	Emissions Control - Chemicals	3,431,831	-	3,431,831	-
	Total Fuel for Electric Generation	98,822,300	-	98,822,300	-
	Memo: NonAff Fuel/Allow/Emissions	98,769,531	-	98,769,531	-
5550004	Purchased Power-Pool Capacity	181,949	0	181,949	0
5550005	Purchased Power - Pool Energy	676,093	0	676,093	0
5550027	Purch Pwr-Non-Fuel Portion-Aff	15,704,126	0	15,704,126	0
5550028	Purch Power-Assoc-Trnsfr Price	0	151,982,444	0	0
5550046	Purch Power-Fuel Portion-Affil	23,760,982	0	23,760,982	0
5550101	Purch Power-Pool Non-Fuel -Aff	168,508	0	168,508	0
5550102	Pur Power-Pool NonFuel-OSS-Aff	214,985	0	214,985	0
	Purchased Electricity from AEP - Affiliates	40,706,643	151,982,444	40,706,643	-
5550000	Purchased Power	139	0	137	2
5550001	Purch Pwr-NonTrading-Nonassoc	166,179	0	166,179	0
5550032	Gas Conversion-Mone Plant	(7,293)	0	(7,293)	0
5550039	PJM Inadvertent Mtr Res-OSS	(70,801)	0	(70,801)	0
5550040	PJM Inadvertent Mtr Res-LSE	(38,467)	0	(38,467)	0
5550041	PJM Ancillary Serv -Sync	587	0	587	0
5550074	PJM Reactive-Charge	(11,793)	0	(11,793)	0
5550076	PJM Black Start-Charge	486,219	0	486,219	0
5550077	PJM Black Start-Credit	(3,975)	0	(3,975)	0
5550078	PJM Regulation-Charge	1,196,066	0	1,196,066	0
5550079	PJM Regulation-Credit	(299,925)	0	(299,925)	0
5550083	PJM Spinning Reserve-Charge	1,055,245	0	1,055,245	0
5550084	PJM Spinning Reserve-Credit	(269,542)	0	(269,542)	0
5550090	PJM 30m Suppl Rserv Charge LSE	385,327	0	385,327	0
5550099	PJM Purchases-non-ECR Auction	1,312,567	0	1,312,567	0
5550100	Capacity Purchases-Auction	28,516	0	28,516	0
5550107	Capacity purchases - Trading	36,779	0	36,779	0
	Purchased Electricity for Resale - NonAffiliated	3,965,829	-	3,965,827	2
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	44,672,472	151,982,444	44,672,470	2
	GROSS MARGIN	155,496,525	60,769,210	76,436,075	30,623,685

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Layout: GLS8016

098 V2014-04-30	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Apr 2014	Kentucky Power Company - Distribution 110 Actual YTD Apr 2014	Kentucky Power Company - Generation 117 Actual YTD Apr 2014	Kentucky Power Company - Transmission 180 Actual YTD Apr 2014
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	1,271,650	0	1,271,650	0
5000001	Oper Super & Eng-RATA-Affil	52,712	0	52,712	0
5020000	Steam Expenses	830,515	0	830,515	0
5050000	Electric Expenses	195,699	0	195,699	0
5060000	Misc Steam Power Expenses	2,810,032	0	2,810,032	0
5060002	Misc Steam Power Exp-Assoc	20,633	0	20,633	0
5060003	Removal Cost Expense - Steam	(71,189)	0	(71,189)	0
5060004	NSR Settlement Expense	(1,427)	0	(1,427)	0
5060025	Misc Stm Pwr Exp Environmental	(11)	0	(11)	0
	Steam Generation Op Exp	**5,108,614**	-	**5,108,614**	-
	Nuclear Generation Op Exp	-	-	-	-
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	179,103	83	178,785	235
5570000	Other Expenses	605,606	411	605,001	194
5570007	Other Pwr Exp - Wholesale RECs	10,651	10,651	0	0
5757000	PJM Admin-MAM&SC- OSS	192,676	0	192,676	0
5757001	PJM Admin-MAM&SC- Internal	269,665	0	269,665	(0)
	Other Generation Op Exp	**1,257,701**	**11,145**	**1,246,127**	**429**
5600000	Oper Supervision & Engineering	343,843	829	1,612	341,402
5611000	Load Dispatch - Reliability	3,431	0	0	3,431
5612000	Load Dispatch-Mntr&Op TransSys	289,245	37	62	289,146
5614000	PJM Admin-SSC&DS-OSS	165,658	0	165,658	0
5614001	PJM Admin-SSC&DS-Internal	241,986	0	241,986	0
5614007	RTO Admin Default LSE	3,874	0	3,539	335
5614008	PJM Admin Defaults OSS	2,417	0	2,417	0
5615000	Reliability,Plng&Stds Develop	36,383	2,923	4,448	29,012
5618000	PJM Admin-RP&SDS-OSS	46,619	0	46,619	0
5618001	PJM Admin-RP&SDS- Internal	65,695	0	65,695	0
5620001	Station Expenses - Nonassoc	57,760	0	0	57,760
5630000	Overhead Line Expenses	59,201	0	0	59,201
5650002	Transmssn Elec by Others-NAC	73,225	0	73,225	0
5650007	Tran Elec by Oth-Aff Trn Price	0	12,121,705	0	0
5650012	PJM Trans Enhancement Charge	1,268,413	0	1,268,413	0
5650015	PJM TO Serv Exp - Aff	15,382	0	15,382	0
5650016	PJM NITS Expense - Affiliated	1,250,760	0	1,250,760	0
5650019	Affil PJM Trans Enhncement Exp	64,388	0	64,388	0
5650020	PROVISION PJM NITS Affl Expens	(124,256)	0	(124,256)	0
5660000	Misc Transmission Expenses	457,159	4,583	6,119	446,457
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	210,740
5757002	SPP Admin-MAM&SC	0	0	0	0
	Transmission Op Exp	**4,321,433**	**12,130,076**	**3,086,068**	**1,437,733**
5800000	Oper Supervision & Engineering	248,926	244,896	1,478	2,552
5810000	Load Dispatching	1,545	931	0	615
5820000	Station Expenses	67,763	62,713	0	5,051
5830000	Overhead Line Expenses	287,131	287,189	(135)	77
5840000	Underground Line Expenses	23,608	23,436	126	46
5841000	Oper of Energy Storage Equip	0	0	0	0
5850000	Street Lighting & Signal Sys E	39,369	39,369	0	0
5860000	Meter Expenses	269,781	269,412	16	353
5870000	Customer Installations Exp	52,410	52,410	0	0
5880000	Miscellaneous Distribution Exp	1,341,637	1,329,946	2,463	9,229
5890001	Rents - Nonassociated	478,965	478,965	0	0
5890002	Rents - Associated	26,609	26,609	0	0
	Distribution Op Exp	**2,837,743**	**2,815,874**	**3,948**	**17,922**
9010000	Supervision - Customer Accts	98,305	98,231	54	20
9020000	Meter Reading Expenses	5,323	5,134	138	51
9020001	Customer Card Reading	325	97	167	61
9020002	Meter Reading - Regular	132,427	132,427	0	0
9020003	Meter Reading - Large Power	16,947	16,947	0	0
9020004	Read-In & Read-Out Meters	20,499	20,499	0	0
9030000	Cust Records & Collection Exp	119,748	117,060	435	2,254
9030001	Customer Orders & Inquiries	814,885	814,820	61	4
9030002	Manual Billing	13,260	12,792	5	464
9030003	Postage - Customer Bills	264,544	264,544	0	0
9030004	Cashiering	36,653	35,781	441	431
9030005	Collection Agents Fees & Exp	20,595	20,595	0	0
9030006	Credit & Oth Collection Activ	242,740	242,692	36	12
9030007	Collectors	189,801	189,801	0	0
9030009	Data Processing	56,094	56,082	9	3
9040007	Uncoll Accts - Misc Receivable	(23,902)	(28,627)	4,725	0
9050000	Misc Customer Accounts Exp	9,929	9,929	0	0

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Layout: GLS8016
098 V2014-04-30 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account	Description	Kentucky Power Int Consol GLS8016 Actual YTD Apr 2014	Kentucky Power Company - Distribution 110 Actual YTD Apr 2014	Kentucky Power Company - Generation 117 Actual YTD Apr 2014	Kentucky Power Company - Transmission 180 Actual YTD Apr 2014
9070000	Supervision - Customer Service	48,993	48,989	2	2
9070001	Supervision - DSM	(3)	(1)	(1)	(1)
9080000	Customer Assistance Expenses	163,107	163,109	(1)	(1)
9080001	DSM-Customer Advisory Grp	862	862	0	0
9080009	Cust Assistance Expense - DSM	1,896,215	1,895,427	569	220
9090000	Information & Instruct Advrts	27,061	8,088	13,899	5,074
9100000	Misc Cust Svc&Informational Ex	5,217	2,729	1,942	546
	Customer Service and Information Op Exp	**4,159,626**	**4,128,006**	**22,479**	**9,141**
9120000	Demonstrating & Selling Exp	5,532	5,532	0	0
9120003	Demo & Selling Exp - Area Dev	(321)	(321)	0	0
	Sales Expenses	**5,210**	**5,210**	-	-
	Memo: Insurance (9240 9250)	**459,441**	**114,315**	**262,098**	**83,028**
9200000	Administrative & Gen Salaries	3,064,847	1,404,499	1,190,814	469,534
9210001	Off Supl & Exp - Nonassociated	244,780	132,848	76,969	34,964
9210003	Office Supplies & Exp - Trnsf	6	6	0	0
9220000	Administrative Exp Trnsf - Cr	(182,437)	(182,437)	0	0
9220001	Admin Exp Trnsf to Cnstrction	(143,720)	(143,720)	0	0
9220004	Admin Exp Trnsf to ABD	(528)	(528)	0	0
9230001	Outside Svcs Empl - Nonassoc	415,936	175,829	177,333	62,774
9230002	Outside Svcs Empl - Assoc	(0)	0	(0)	0
9230003	AEPSC Billed to Client Co	(64,134)	(21,787)	(24,084)	(18,264)
9240000	Property Insurance	156,245	55,167	36,539	64,539
9250000	Injuries and Damages	367,248	264,793	87,844	14,610
9250001	Safety Dinners and Awards	1,239	516	495	228
9250002	Emp Accident Prvntion-Adm Exp	3,480	2,201	868	410
9250004	Injuries to Employees	732	0	732	0
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(104,551)	(148,649)	36,753	7,344
9250007	Prsnal Injries&Prop Dmage-Pub	104,245	162	104,039	43
9250010	Frg Ben Loading - Workers Comp	(69,195)	(59,876)	(5,172)	(4,147)
9260000	Employee Pensions & Benefits	1,653	1,653	0	0
9260001	Edit & Print Empl Pub-Salaries	5,235	1,879	2,163	1,193
9260002	Pension & Group Ins Admin	17,520	9,244	7,328	948
9260003	Pension Plan	1,640,042	764,538	784,302	91,202
9260004	Group Life Insurance Premiums	51,380	20,861	27,170	3,349
9260005	Group Medical Ins Premiums	1,660,793	851,078	675,691	134,024
9260006	Physical Examinations	1	0	0	1
9260007	Group L-T Disability Ins Prem	5,300	2,730	2,189	382
9260009	Group Dental Insurance Prem	92,640	48,648	37,696	6,296
9260010	Training Administration Exp	42	16	25	2
9260012	Employee Activities	813	148	235	430
9260014	Educational Assistance Pmts	450	450	0	0
9260021	Postretirement Benefits - OPEB	(1,222,813)	(581,548)	(560,389)	(80,875)
9260027	Savings Plan Contributions	697,477	285,058	383,346	29,073
9260036	Deferred Compensation	1,956	1,956	0	0
9260037	Supplemental Pension	80	80	0	0
9260040	SFAS 112 Postemployment Benef	424,688	0	424,688	0
9260050	Frg Ben Loading - Pension	(385,744)	(282,924)	(80,574)	(22,246)
9260051	Frg Ben Loading - Grp Ins	(501,270)	(375,017)	(88,869)	(37,384)
9260052	Frg Ben Loading - Savings	(214,237)	(133,281)	(65,510)	(15,446)
9260053	Frg Ben Loading - OPEB	122,497	94,526	17,439	10,532
9260055	IntercoFringeOffset- Don't Use	(490,743)	(112,527)	(332,302)	(45,914)
9260057	Postret Ben Medicare Subsidy	206,823	83,063	115,879	7,880
9260058	Frg Ben Loading - Accrual	(172,336)	(95,389)	(62,551)	(14,395)
9260060	Amort-Post Retirement Benefit	72,207	43,194	23,736	5,277
9270000	Franchise Requirements	46,924	46,924	0	0
9280000	Regulatory Commission Exp	10,594	3,745	4,444	2,405
9280001	Regulatory Commission Exp-Adm	8	3	2	3
9280002	Regulatory Commission Exp-Case	39,485	6,013	29,465	4,007
9301000	General Advertising Expenses	848	298	362	187
9301001	Newspaper Advertising Space	2,082	741	877	463
9301002	Radio Station Advertising Time	20	7	9	5
9301010	Publicity	1,841	654	786	400
9301012	Public Opinion Surveys	14,833	14,832	0	1
9301015	Other Corporate Comm Exp	5,197	3,698	985	514
9302000	Misc General Expenses	76,640	30,369	25,710	20,561
9302003	Corporate & Fiscal Expenses	17,246	3,135	13,625	486
9302004	Research, Develop&Demonstr Exp	1,708	1,708	0	0
9302458	AEPSC Non Affiliated expenses	(0)	0	(0)	0
9310001	Rents - Real Property	33,041	33,041	0	0
9310002	Rents - Personal Property	79,858	51,553	24,480	3,825
	Administration & General	**6,139,172**	**2,304,183**	**3,095,767**	**739,222**
4111005	Accretion Expense	320,335	0	320,335	0
	Accretion	**320,335**	-	**320,335**	-
4116000	Gain From Disposition of Plant	(1,340)	(1,340)	0	0

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American Electric Power

INCOME STATEMENT

GLS8016
YTD Apr 2014
05/08/2014 16:37

08B V2014-04-30	Layout: GLS8016 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Apr 2014	Kentucky Power Company - Distribution 110 Actual YTD Apr 2014	Kentucky Power Company - Generation 117 Actual YTD Apr 2014	Kentucky Power Company - Transmission 180 Actual YTD Apr 2014
	Loss/(Gain) on Utility Plant	**(1,340)**	**(1,340)**	-	-
9302006	Assoc Bus Dev - Materials Sold	22,546	22,546	0	0
9302007	Assoc Business Development Exp	34,778	25,547	39	9.192
	Associated Business Development Expenses	**57,325**	**48,094**	**39**	**9,192**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4265009	Factored Cust A/R Exp - Affil	314,673	314,673	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	664,844	664,844	0	0
	Opr Exp and Factored A/R	**979,517**	**979,517**	-	-
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	28,258	10,080	12,285	5,893
	Expense of Non-Utility Operation	**28,258**	**10,080**	**12,285**	**5,893**
4210009	Misc Non-Op Exp - NonAssoc	4,142	712	2,980	450
	Misc NonOp Expenses - NonAssoc	**4,142**	**712**	**2,980**	**450**
4261000	Donations	149,184	81,966	59,693	7,525
	Donation Contributions	**149,184**	**81,966**	**59,693**	**7,525**
4263001	Penalties	61,710	23,529	24,132	14,050
	Provision for Penalties	**61,710**	**23,529**	**24,132**	**14,050**
4264000	Civic & Political Activities	93,326	34,612	37,599	21,115
	Civic & Political Activities	**93,326**	**34,612**	**37,599**	**21,115**
4265002	Other Deductions - Nonassoc	42	12	22	8
4265033	Transition Costs	5,226	0	5,226	0
	Other Deductions	**5,267**	**12**	**5,247**	**8**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**1,321,404**	**1,130,428**	**141,936**	**49,040**
	Operational Expenses	**25,527,224**	**22,571,677**	**13,025,313**	**2,262,679**
5100000	Maint Supv & Engineering	1,281,811	0	1,281,811	0
5110000	Maintenance of Structures	599,062	0	599,062	0
5120000	Maintenance of Boiler Plant	5,711,339	0	5,711,339	0
5130000	Maintenance of Electric Plant	1,028,996	0	1,028,996	0
5140000	Maintenance of Misc Steam Plt	480,508	0	480,508	0
	Steam Generation Maintenance	**9,101,716**	-	**9,101,716**	-
	Nuclear Generation Maintenance	-	-	-	-
	Hydro Generation Maintenance	-	-	-	-
	Other Generation Maintenance	-	-	-	-
5680000	Maint Supv & Engineering	28,934	0	9	28,925
5690000	Maintenance of Structures	3,058	0	0	3,058
5691000	Maint of Computer Hardware	6,998	19	14	6,965
5692000	Maint of Computer Software	94,734	1,579	0	93,155
5693000	Maint of Communication Equip	7,424	0	0	7,424
5700000	Maint of Station Equipment	285,087	18,114	0	266,973
5710000	Maintenance of Overhead Lines	415,918	(1,490)	0	417,408
5720000	Maint of Underground Lines	161	0	0	161
5730000	Maint of Misc Trnsmssion Plt	106,171	0	0	106,171
	Transmission Maintenance	**948,486**	**18,223**	**23**	**930,239**
5900000	Maint Supv & Engineering	750	736	(1)	14
5910000	Maintenance of Structures	5,002	4,317	0	685
5920000	Maint of Station Equipment	260,006	252,262	55	7,689
5930000	Maintenance of Overhead Lines	10,801,977	10,799,475	2,578	(75)
5930001	Tree and Brush Control	119,377	119,377	0	0
5930008	Maint Ovh Lines Strm Exp-OvUnd	1,292	1,292	0	0
5930010	Storm Expense Amortization	1,566,148	1,566,148	0	0
5940000	Maint of Underground Lines	31,071	31,070	0	1
5950000	Maint of Lne Trnf Rglators&Dvi	24,071	24,071	0	0
5960000	Maint of Strt Lghtng & Sgnal S	20,930	20,929	0	0
5970000	Maintenance of Meters	29,029	27,956	0	1,073
5980000	Maint of Misc Distribution Plt	79,811	79,200	0	611
	Distribution Maintenance	**12,939,462**	**12,926,832**	**2,631**	**9,999**
9350001	Maint of Structures - Owned	100,864	98,716	(123)	2,271
9350002	Maint of Structures - Leased	18,482	18,482	(0)	(0)
9350003	Maint of Prprty Held Fture Use	451	(1)	454	(1)
9350006	Maint of Carrier Equipment	13	13	0	0
9350012	Maint of Data Equipment	346	0	346	0
9350013	Maint of Cmmncation Eq-Unall	277,194	254,967	22,227	0
9350015	Maint of Office Furniture & Eq	223,674	100,907	122,767	0
9350019	Maint of Gen Plant-SCADA Equ	126	124	2	0
9350024	Maint of DA-AMI Comm Equip	8	8	0	0
	Administration & General Maintenance	**621,158**	**473,216**	**145,672**	**2,270**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**23,610,822**	**13,418,272**	**9,250,043**	**942,508**
	Total Operational and Maintenance Expenses	**49,138,047**	**35,989,948**	**22,275,355**	**3,205,187**

American Electric Power

INCOME STATEMENT

GLS8016
YTD Apr 2014
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Layout: GLS8016

098 V2014-04-30	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Apr 2014	Kentucky Power Company - Distribution 110 Actual YTD Apr 2014	Kentucky Power Company - Generation 117 Actual YTD Apr 2014	Kentucky Power Company - Transmission 180 Actual YTD Apr 2014
4040001	Amort. of Plant	1,136,932	503,396	442,290	191,247
4060001	Amort of Plt Acq Adj	12,872	0	0	12,872
	DDA Amortization	**1,149,804**	**503,396**	**442,290**	**204,119**
4073000	Regulatory Debits	96,362	0	0	96,362
	DDA Regulatory Debits	**96,362**	-	-	**96,362**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**1,246,166**	**503,396**	**442,290**	**300,481**
4030001	Depreciation Exp	29,588,202	8,426,751	18,268,598	2,892,854
	DDA Depreciation	**29,588,202**	**8,426,751**	**18,268,598**	**2,892,854**
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	538,655	0	538,655	0
	DDA Asset Retirement Obligation	**538,655**	-	**538,655**	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**30,126,857**	**8,426,751**	**18,807,253**	**2,892,854**
	Depreciation and Amortization	**31,373,023**	**8,930,146**	**19,249,543**	**3,193,335**
	Franchise Taxes	-	-	-	-
408100613	State Gross Receipts Tax	(5,942)	1	(5,943)	0
408100614	State Gross Receipts Tax	20,000	0	20,000	0
	Revenue-kWhr Taxes	**14,058**	**1**	**14,057**	-
4081002	FICA	1,408,893	553,511	798,651	56,731
4081003	Federal Unemployment Tax	18,049	7,859	9,306	885
4081007	State Unemployment Tax	57,644	19,678	35,719	2,247
4081033	Fringe Benefit Loading - FICA	(388,431)	(241,320)	(118,376)	(28,735)
4081034	Fringe Benefit Loading - FUT	(2,360)	(1,571)	(633)	(155)
4081035	Fringe Benefit Loading - SUT	(5,665)	(3,392)	(1,944)	(329)
	Payroll Taxes	**1,088,131**	**334,766**	**722,721**	**30,644**
408102014	State Business Occup Taxes	1,324,190	0	1,324,190	0
	Capacity Taxes	**1,324,190**	-	**1,324,190**	-
408100510	Real Personal Property Taxes	131	131	0	0
408100512	Real Personal Property Taxes	953,332	0	953,332	0
408100513	Real Personal Property Taxes	3,410,480	1,997,748	300,772	1,111,960
408102913	Real-Pers Prop Tax-Cap Leases	1,038	790	68	180
408102914	Real-Pers Prop Tax-Cap Leases	7,164	5,408	416	1,340
408103613	Real Prop Tax-Cap Leases	(1,473)	(1,473)	0	0
408103614	Real Prop Tax-Cap Leases	8,500	8,500	0	0
408200513	Real Personal Property Taxes	18,868	3,224	0	15,644
	Property Taxes	**4,398,040**	**2,014,327**	**1,254,588**	**1,129,124**
408101813	St Publ Serv Comm Tax-Fees	315,415	315,415	0	0
	Regulatory Fees	**315,415**	**315,415**	-	-
408101414	Federal Excise Taxes	986	0	986	0
	Production Taxes	**986**	-	**986**	-
408101714	St Lic Rgstrtion Tax-Fees	200	200	0	0
408101900	State Sales and Use Taxes	(342,470)	(156,655)	(178,775)	(7,040)
408101912	State Sales and Use Taxes	218,039	89,065	119,078	9,896
408101913	State Sales and Use Taxes	1,295	1,295	0	0
408101914	State Sales and Use Taxes	6,198	6,198	0	0
	Miscellaneous Taxes	**(116,738)**	**(59,897)**	**(59,697)**	**2,856**
	Other Non-Income Taxes	**(115,752)**	**(59,897)**	**(58,711)**	**2,856**
	Taxes Other Than Income Taxes	**7,024,082**	**2,604,613**	**3,256,845**	**1,162,624**
	TOTAL OPERATING EXPENSES	**87,535,152**	**47,524,707**	**44,781,743**	**7,561,146**
	Memo: SEC Total Operating Expenses	**231,029,924**	**199,507,151**	**188,276,513**	**7,561,148**
	OPERATING INCOME	**67,961,373**	**13,244,503**	**31,654,332**	**23,062,539**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	7,276	6,966	(218)	528
	Interest & Dividend NonAffiliated	**7,276**	**6,966**	**(218)**	**528**
4190001	Interest Inc - Assoc Non CBP	7,747	7,747	0	0
4190005	Interest Income - Assoc CBP	9,692	1,121	(24,952)	33,523
	Interest & Dividend Affiliated	**17,438**	**8,867**	**(24,952)**	**33,523**
	Total Interest & Dividend Income	**24,714**	**15,833**	**(25,170)**	**34,051**
4210039	Carrying Charges	21,664	0	0	21,664
	Interest & Dividend Carrying Charge	**21,664**	-	-	**21,664**
	Memo: Total Interest & Dividend Income w/ Carrying	**46,378**	**15,833**	**(25,170)**	**55,715**
4191000	Allw Oth Fnds Usd Drng Cnstr	1,907,040	171,460	1,212,526	523,055
	AFUDC	**1,907,040**	**171,460**	**1,212,526**	**523,055**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
	Interest LTD IPC	-	-	-	-
4300001	Interest Exp - Assoc Non-CBP	350,000	139,122	102,963	107,916
	Interest LTD Notes Payable - Affiliated	**350,000**	**139,122**	**102,963**	**107,916**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-

American Electric Power

INCOME STATEMENT

GLS8016
YTD Apr 2014
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Layout: GLS8016
08B V2014-04-30 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

		Kentucky Power Int Consol GLS8016 Actual	Kentucky Power Company - Distribution 110 Actual	Kentucky Power Company - Generation 117 Actual	Kentucky Power Company - Transmission 180 Actual
		YTD Apr 2014	YTD Apr 2014	YTD Apr 2014	YTD Apr 2014
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	11,332,902	4,504,715	3,333,913	3,494,274
	Interest LTD Senior Unsecured	11,332,902	4,504,715	3,333,913	3,494,274
4270012	PCRB Interest Exp-Assoc	7,747	7,747	0	0
	Interest LTD Other - Affil	7,747	7,747	-	-
4270005	Int on LTD - Other LTD	959,722	966,319	(6,597)	0
	Interest LTD Other - NonAffil	959,722	966,319	(6,597)	-
	Interest on Long-Term Debt	12,650,371	5,617,903	3,430,279	3,602,189
4300003	Int to Assoc Co - CBP	19,332	2,234	112,045	(94,947)
	Interest STD - Affil	19,332	2,234	112,045	(94,947)
4310007	Lines Of Credit	262,392	106,127	132,702	23,562
	Interest STD - NonAffil	262,392	106,127	132,702	23,562
	Interest on Short Term Debt	281,724	108,362	244,747	(71,385)
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	157,062	62,431	46,205	48,427
	Amort of Debt Disc. Prem & Exp	157,062	62,431	46,205	48,427
4281004	Amrtz Loss Rcqured Debt-Dbnt	11,216	4,458	3,300	3,458
	Amort Loss on Reacquired Debt	11,216	4,458	3,300	3,458
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	52,456	20,228	27,171	5,058
4310002	Interest on Customer Deposits	9,065	9,065	0	0
4310023	Interest Expense - State Tax	1,095	545	523	27
	Other Interest - NonAffil	62,616	29,838	27,694	5,085
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(993,178)	(88,636)	(633,984)	(270,558)
	AFUDC-Borrowed Funds	(993,178)	(88,638)	(633,984)	(270,558)
	Total Interest Charges	12,169,812	5,734,355	3,118,239	3,317,217
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	57,744,979	7,697,440	29,723,448	20,324,091
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	17,090,564	3,309,864	8,149,977	5,630,723
4092001	Inc Tax, Oth Inc&Ded-Federal	(234,375)	(144,483)	(70,500)	(19,393)
	Federal Current Income Tax	16,856,189	3,165,382	8,079,477	5,611,330
4101001	Prov Def I/T Util Op Inc-Fed	19,633,922	1,912,366	16,391,224	1,330,331
4102001	Prov Def I/T Oth I&D - Federal	198,736	125,084	50,258	23,395
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(18,257,310)	(2,712,884)	(15,058,186)	(486,240)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(20,438)	0	(20,438)	0
	Federal Deferred Income Tax	1,554,912	(675,433)	1,362,858	867,487
4114001	ITC Adj, Utility Oper - Fed	(32,013)	(5,040)	(7,704)	(19,269)
	Federal Investment Tax Credits	(32,013)	(5,040)	(7,704)	(19,269)
	Federal Income Taxes	18,379,088	2,484,909	9,434,631	6,459,548
409100214	Income Taxes UOI - State	2,965,449	352,814	1,642,393	970,241
409200214	Inc Tax Oth Inc Ded - State	(40,680)	(25,078)	(12,237)	(3,366)
	State Current Income Tax	2,924,768	327,736	1,630,157	966,875
4111002	Prv Def I/T-Cr UtilOpInc-State	(203,840)	0	(203,840)	0
	State Deferred Income Tax	(203,840)	-	(203,840)	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	2,720,928	327,736	1,426,317	966,875
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	21,100,016	2,812,845	10,860,948	7,426,423
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	38,644,963	4,884,795	18,862,500	12,897,668
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	36,644,963	4,884,785	18,862,500	12,897,668
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	36,644,963	4,884,795	18,862,500	12,897,668
	NET INCOME (LOSS) NODE before PS	36,844,963	4,884,795	18,862,500	12,897,668
	Double Check on Net Income Node after PS	(0)	(0)	-	(0)

American Electric Power

INCOME STATEMENT

GLS8016
YTD Apr 2014
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Layout: GLS8016

09B V2014-04-30 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Apr 2014	Kentucky Power Company - Distribution 110 Actual YTD Apr 2014	Kentucky Power Company - Generation 117 Actual YTD Apr 2014	Kentucky Power Company - Transmission 180 Actual YTD Apr 2014
Reserved Section				

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Apr 2014
05/08/2014 14:52

Layout : GLS8216

09B V2014-04- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Apr 2014	YTD Apr 2014	YTD Apr 2014	YTD Apr 2014
ASSETS				
Cash and Cash Equivalents	663,352	663,352	0	0
Other Cash Deposits	0	0	0	0
Customers	24,492,390	13,339,802	10,341,516	811,073
Accrued Unbilled Revenues	(14,018,863)	(14,018,863)	0	0
Miscellaneous Accounts Receivable	31,752,712	5,287,421	70,574,374	7,331,584
Allowances for Uncollectible Accounts	(60,563)	(48,935)	(11,628)	0
Accounts Receivable	42,165,676	4,559,425	80,904,262	8,142,656
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	79,675,672	2,556,112	76,163,068	956,492
Risk Management Contracts - Current	2,920,709	(1,178)	2,921,887	0
Margin Deposits	1,126,506	18,255	1,108,251	0
Unrecovered Fuel - Current	11,186,588	0	11,186,588	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	2,075,549	1,679,180	316,594	79,774
TOTAL CURRENT ASSETS	139,814,051	9,475,146	172,600,650	9,178,922
Electric Production	1,064,695,670	744,696,878	1,496,505,596	507,834,025
Electric Transmission	511,321,923	0	0	0
Electric Distribution	700,231,136	0	0	0
General Property, Plant and Equipment	478,317,005	199,571	4,169,386	1,160,479
Construction Work-In-Progress	145,473,712	16,464,707	89,595,288	39,413,718
TOTAL PROPERTY, PLANT and EQUIPMENT	2,900,039,446	761,360,955	1,590,270,270	548,408,221
less: Accumulated Depreciation and Amortization	(969,039,294)	(237,874,559)	(562,510,397)	(168,654,339)
NET PROPERTY, PLANT and EQUIPMENT	1,931,000,152	523,486,396	1,027,759,873	379,753,882
Net Regulatory Assets	215,418,015	102,527,722	57,238,305	55,651,988
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	1,793,141	(17)	1,793,158	0
Employee Benefits and Pension Assets	13,625,169	(1,067,934)	14,387,530	305,573
Other Non Current Assets	13,027,308	5,464,119	4,750,512	2,812,677
TOTAL OTHER NON-CURRENT ASSETS	243,863,633	106,923,890	78,169,505	58,770,239
TOTAL ASSETS	2,314,677,837	639,885,432	1,278,530,028	447,703,044
LIABILITIES				
Accounts Payable	78,263,402	58,415,024	67,736,475	3,552,569
Advances from Affiliates	24,309,197	(10,329,610)	167,176,133	(132,537,326)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	0	0	0	0
Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
Risk Management Liabilities	826,950	0	826,950	0
Accrued Taxes	25,481,904	8,146,926	4,259,837	13,075,141
Memo. Property Taxes	13,699,487	6,202,014	3,671,205	3,826,268
Accrued Interest	8,546,512	3,382,305	2,557,976	2,606,232
Risk Management Collateral	691,344	0	691,344	0
Utility Customer Deposits	24,510,548	24,510,548	0	0
Deposits - Customer and Collateral	25,201,892	24,510,548	691,344	0
Over-Recovered Fuel Costs - Current	0	0	0	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,445,590	515,416	786,510	143,664
Tax Collections Payable	1,988,038	1,894,343	88,300	5,396
Revenue Refunds - Accrued	1,378,946	0	259,350	1,119,596
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	2,258,587	869,925	1,281,324	107,338
Accrued Rents	(28,131)	(28,131)	0	0

H:\GL\MK Team\Regulatory & Governmental Reports\Kentucky Power Monthly Report KPSC\2014\2014 04 April\2014_4 GLS8216.xls

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Apr 2014
05/09/2014 14:52

Layout : GLS8216

09B V2014-04- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS		Kentucky Power Int Consol GLS8216 YTD Apr 2014	Kentucky Power Company - 110 YTD Apr 2014	Kentucky Power Company - Generation 117 YTD Apr 2014	Kentucky Power Company - 180 YTD Apr 2014
	Accrued ICP	2,341,744	903,095	1,350,500	88,149
	Accrued Vacations	5,796,954	2,246,373	3,283,477	267,104
	Misc Employee Benefits	1,232,401	424,860	793,308	14,233
	Payroll Deductions	222,977	98,539	109,771	14,667
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	765,214	309,261	416,502	39,452
2530022	Customer Advance Receipts	1,359,231	1,359,231	0	0
	Customer Advance	1,359,231	1,359,231	0	0
2420511	Control Cash Disburse Account	1,606,722	1,606,722	0	0
	Control Cash Disbursement Account	1,606,722	1,606,722	0	0
	JMG Liability	0	0	0	0
2420088	Econ. Development Fund Curr	291,250	0	291,250	0
2420512	Unclaimed Funds	4,271	4,271	0	0
2420542	Acc Cash Franchise Req	88,021	88,021	0	0
242059214	Sales Use Tax - Lease Equip	340	222	43	75
2420643	Accrued Audit Fees	151,138	40,673	84,939	25,526
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	246,141	0	246,141	0
2530050	Deferred Rev -Pole Attachments	145,121	145,121	0	0
2530112	Other Deferred Credits-Curr	653,180	0	653,180	0
2530124	Contr In Aid of Constr Advance	69,242	69,242	0	0
	Misc Current and Accrued Liabilities	2,203,032	347,551	1,829,880	25,601
	Current Other and Accrued Liabilities	21,125,716	10,031,769	9,412,412	1,681,535
	Other Current Liabilities	**22,571,305**	**10,547,185**	**10,198,922**	**1,825,198**
	TOTAL CURRENT LIABILITIES	**185,201,163**	**94,672,377**	**253,447,638**	(111,478,186)
	Long-Term Debt - Affiliated	**20,000,000**	**7,949,800**	**5,883,600**	**6,166,600**
	Long-Term Debt - Non Affiliated	**730,000,000**	**210,669,700**	**355,915,400**	**163,414,900**
	Long-Term Debt - Premiums and Discounts Unamort	(555,750)	(220,905)	(163,491)	(171,354)
	Memo - LTD NonAffiliated and Premiums	*729,444,250*	*210,448,795*	*355,751,909*	*163,243,546*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	790,013	571	789,442	0
2440022	L/T Liability MTM Collateral	(2,897)	0	(2,897)	0
	Long-Term Risk Management Liabilities - MTM	787,116	571	786,545	0
	Long-Term Risk Management Liabilities	**787,116**	**571**	**786,545**	**0**
	Deferred Income Taxes	**555,947,931**	**168,193,003**	**268,943,744**	**118,811,184**
	Deferred Investment Tax Credits	**93,734**	**19,125**	**30,124**	**44,486**
	Regulatory Liabilities and Deferred Credits	**22,935,856**	(31,450,818)	**60,710,443**	(6,323,769)
	Memo - Reg Liab and Def ITC	*23,029,590*	*(31,431,693)*	*60,740,566*	*(6,279,284)*
	Asset Retirement Obligation	**20,646,325**	**62,120**	**20,584,204**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,962,740**	**3,131,511**	**4,726,572**	**104,657**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Rede	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	3,966,321	1,423,423	2,062,992	479,906
	Def Credits - Income Tax	681,409	361,821	277,000	42,588
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	116,031	116,031	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	1,732,211	0	1,732,211	0
2530001	Deferred Revenues	5,612	5,612	0	0
2530067	IPP - System Upgrade Credits	271,729	0	0	271,729
2530092	Fbr Opl Lns-In Kind Sv-Dfd Gns	154,776	154,776	0	0
2530137	Fbr Opl Lns-Sold-Defd Rev	98,655	0	0	98,655
	Def Credits - Other	2,262,983	160,388	1,732,211	370,384
	Total Other Deferred Credits	2,379,014	276,419	1,732,211	370,384
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	873,750	0	873,750	0
	Other Non-Current Liabilities	**9,011,138**	**2,061,664**	**6,056,597**	**892,877**

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Apr 2014
05/08/2014 14:52

Layout : GLS8216

09B V2014-04~ Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Apr 2014	Kentucky Power Company - 110 YTD Apr 2014	Kentucky Power Company - Generation 117 YTD Apr 2014	Kentucky Power Company - 180 YTD Apr 2014
TOTAL NON-CURRENT LIABILITIES	1,366,829,089	360,415,772	723,473,738	282,939,579
TOTAL LIABILITIES	1,552,030,252	455,088,149	976,921,377	171,461,393
Cumulative Pref Stocks of Subs - Not subject Mand Redem	0	0	0	0
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS' EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	517,459,453	106,025,371	327,394,246	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	201,335,887	56,447,919	(29,617,598)	174,505,566
Accumulated Other Comprehensive Income (Loss)	(6,597,756)	(80,057)	(6,455,600)	(62,099)
TOTAL SHAREHOLDERS' EQUITY	762,647,584	184,797,283	301,608,651	276,241,650
Memo: Total Equity	762,647,584	184,797,283	301,608,651	276,241,650
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	2,314,677,837	639,885,432	1,278,530,028	447,703,044
out-of-balance	(0)	0	0	(0)

Reserved Section

Kentucky Power Corp Consol
Comparative Balance Sheet
April 30, 2013

Run Date: 05/09/2013 13:19

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V
KYP_CORP_C(V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS

	Month End Balances 2013	December Balances Last Year	Variance $
ASSETS			
PRODUCTION	560,392,910.59	558,934,668.00	1,458,242.59
TRANSMISSION	490,868,434.64	490,152,082.00	716,352.64
DISTRIBUTION	666,165,245.08	652,615,328.83	13,549,916.25
GENERAL	58,863,060.14	57,451,300.18	1,411,759.96
CONSTRUCTION WORK IN PROGRESS	46,258,404.05	44,281,291.91	1,977,112.14
ELECTRIC UTILITY PLANT	**1,822,548,054.50**	**1,803,434,670.92**	**19,113,383.58**
less Accum Provision - Depre, Depl, Amort.	(636,700,385.91)	(624,238,902.51)	(12,461,483.40)
NET ELECTRIC UTILITY PLANT	**1,185,847,668.59**	**1,179,195,768.41**	**6,651,900.18**
Net NonUtility Property	884,320.47	5,498,717.60	(4,614,397.13)
Investment in Subsidiary & Associated	0.00	0.00	0.00
Other Investments	258,837.67	260,727.67	(1,890.00)
Other Special Funds	0.00	0.00	0.00
Allowance - NonCurrent	2,361,233.00	2,361,232.37	0.63
Long Term Energy Trading Contracts	4,789,174.94	6,881,654.77	(2,092,479.83)
OTHER PROPERTY AND INVESTMENTS	**8,293,566.08**	**15,002,332.41**	**(6,708,766.33)**
Cash and Cash Equivalents	1,310,636.02	1,925,747.09	(615,111.07)
Advances to Affiliates	11,859,253.56	0.00	11,859,253.56
Acct Rec - Customers	12,286,794.46	12,676,052.64	(389,258.18)
Acct Rec - Miscellaneous	4,392,381.13	3,141,697.43	1,250,683.70
Acct Rec - AP for Uncollectible Accounts	(9,817.70)	(141,538.08)	131,720.38
Acct Rec - Associated Companies	6,556,184.15	9,241,088.58	(2,684,904.43)
Fuel Stock	38,624,134.99	69,147,176.47	(30,523,041.48)
Materials and Supplies	22,610,165.98	25,061,279.42	(2,451,113.44)
Accrued Utility Revenues	(7,551,971.25)	816,939.53	(8,368,910.78)
Energy Trading	4,148,601.68	6,174,819.72	(2,026,218.04)
Prepayments	1,238,906.19	1,569,794.80	(330,888.61)
Other Current Assets	1,774,278.81	1,660,942.94	113,335.87
CURRENT ASSETS	**97,239,548.01**	**131,274,000.53**	**(34,034,452.52)**
REGULATORY ASSETS	**217,025,776.98**	**214,900,829.18**	**2,124,947.80**
TOTAL DEFERRED CHARGES	**68,310,117.26**	**78,498,798.33**	**(10,188,681.07)**
TOTAL ASSETS	**1,576,716,676.92**	**1,618,871,728.86**	**(42,155,051.94)**
CAPITALIZATION and LIABILITIES			
COMMON STOCK			
Authorized: 2,000,000 Shares			
Outstanding: 1,009,000 Shares			
Common Stock	50,450,000.00	50,450,000.00	0.00
Premium on Capital Stock	0.00	0.00	0.00
Paid-In-Capital	238,573,780.93	238,341,119.49	232,661.44
Retained Earnings	203,343,368.61	190,818,915.56	12,524,453.05
COMMON SHAREHOLDERS' EQUITY	**492,367,149.54**	**479,610,035.05**	**12,757,114.49**
PS Subject To Mandatory Redemption	0.00	0.00	0.00
PS Not Subject Mandatory Redemption	0.00	0.00	0.00

Kentucky Power Corp Consol
Comparative Balance Sheet
April 30, 2013

Run Date: 05/09/2013 13:19

X_OPR_COS KYP_CORP_C(	Rpt ID: GLR2200V Layout: GLR2200V V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
	CUMULATIVE PREFERRED STOCK	**0.00**	**0.00**	**0.00**
	TRUST PREFERRED SECURITIES	**0.00**	**0.00**	**0.00**
	Long-Term Debt Less Amt Due 1 Yr	**549,277,525.00**	**549,221,950.00**	**55,575.00**
	CAPITALIZATION	**1,041,644,674.54**	**1,028,831,985.05**	**12,812,689.49**
	Obligations Under Capital Lease-NonCurrent	1,915,975.39	1,674,300.89	241,674.50
	Accumulated Provision Rate Relief	704,292.00	1,635,430.00	(931,138.00)
	Accumlated Provision - Miscellanous	35,979,335.42	34,033,794.12	1,945,541.30
	Other NonCurrent Liabilities	**38,599,602.81**	**37,343,525.01**	**1,256,077.80**
	Preferred Stock Due Within 1 Year	0.00	0.00	0.00
	Long-Term Debt Due Within 1 Year	0.00	0.00	0.00
	Accumulated Provision Due Within 1 Year	0.00	0.00	0.00
	Short-Term Debt	0.00	0.00	0.00
	Advances from Affiliates	0.00	13,358,855.63	(13,358,855.63)
	A/P General	18,460,976.57	30,336,776.64	(11,875,800.07)
	A/P Associated Companies	20,616,233.95	41,052,680.18	(20,436,446.24)
	Customer Deposits	24,293,945.54	23,484,964.81	808,980.73
	Taxes Accrued	5,089,833.84	6,548,714.64	(1,458,880.80)
	Interest Accrued	8,102,080.00	7,166,695.02	935,384.98
	Dividends Accrued	0.00	0.00	0.00
	Obligation Under Capital Leases	1,309,467.34	1,403,875.95	(94,408.61)
	Energy Contracts Current	2,097,022.53	3,320,068.02	(1,223,045.49)
	Other Current and Accrued Liabilities	15,658,826.03	17,797,808.10	(2,138,982.07)
	Current Liabilities	**95,628,385.80**	**144,470,438.99**	**(48,842,053.19)**
	Deferred Income Taxes	**388,663,480.28**	**385,153,166.17**	**3,510,314.11**
	Deferred Investment Tax Credits	**279,089.14**	**355,758.82**	**(76,669.68)**
	Regulatory Liabilities	**5,338,208.84**	**13,831,965.72**	**(8,493,756.88)**
2440002	LT Unreal Losses - Non Affil	2,720,170.15	4,200,196.07	(1,480,025.92)
2440022	L/T Liability MTM Collateral	(119,515.00)	(582,545.00)	463,030.00
2450011	L/T Liability-Commodity Hedges	19,903.00	82,731.00	(62,828.00)
	Long-Term Energy Trading Contracts	2,620,558.15	3,700,382.07	(1,079,823.92)
2520000	Customer Adv for Construction	59,351.36	63,177.74	(3,826.38)
	Customer Advances for Construction	59,351.36	63,177.74	(3,826.38)
	Deferred Gains on Sale/Leaseback	0.00	0.00	0.00
	Deferred Gains on Dispostion of Utility Plant	0.00	0.00	0.00
2530000	Other Deferred Credits	0.00	0.00	0.00
2530022	Customer Advance Receipts	1,454,404.02	2,634,497.53	(1,180,093.51)
2530044	Neigh Help Neig-Cust Donations	0.00	0.00	0.00
2530050	Deferred Rev -Pole Attachments	149,998.97	78,940.35	71,058.62
2530067	IPP - System Upgrade Credits	263,073.91	260,279.72	2,794.19
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	160,724.00	162,614.00	(1,890.00)
2530101	MACSS Unidentified EDI Cash	0.00	0.00	0.00

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Kentucky Power Corp Consol
Comparative Balance Sheet
April 30, 2013

Run Date: 05/09/2013 13:19

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V		Month End Balances	December Balances	Variance
KYP_CORP_C(V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS		2013	Last Year	$
2530112	Other Deferred Credits-Curr	987,972.74	1,113,326.72	(125,353.98)
2530114	Federl Mitigation Deferal(NSR)	754,941.55	754,941.55	0.00
2530137	Fbr Opt Lns-Sold-Defd Rev	112,210.82	116,729.42	(4,518.60)
	Other Deferred Credits	3,883,326.01	5,121,329.29	(1,238,003.28)
	Deferred Credits	**6,563,235.52**	**8,884,889.10**	(2,321,653.58)
	DEFERRED CREDITS & REGULATED LIABILITIES	**400,844,013.78**	**408,225,779.81**	(7,381,766.03)
	CAPITAL & LIABILITIES	**1,576,716,676.93**	**1,618,871,728.87**	(42,155,051.94)

Statement of Retained Earnings

	BALANCE AT BEGINNING OF YEAR	**190,818,915.56**	**171,840,462.36**	18,978,453.21
	Net Income (Loss)	18,774,453.05	50,978,453.21	(32,204,000.16)
	Deductions:			
	Dividend Declared On Common Stock	(6,250,000.00)	-32,000,000	25,750,000.00
	Dividend Declared On Preferred Stock	0.00	0	0.00
	Adjustment in Retained Earnings	0.00	0.00	0.00
	Total Deductions	(6,250,000.00)	(32,000,000.00)	25,750,000.00
	BALANCE AT END OF PERIOD (A)	**203,343,368.61**	**190,818,915.56**	12,524,453.05

(A) Represents The Following Balances At End Of Period

215.0	Appropriated Retained Earnings	0.00	0.00	0.00
215.1	Appr Retnd Erngs - Amrt Rsv, Fed	0.00	0.00	0.00
	Total Appropriated Retained Earnings	0.00	0.00	0.00
2160000-1	Unapprp Retained Earnings Unrestr	190,818,915.56	171,840,462.36	18,978,453.21
2160002+	Unapprp Retained Earnings Restr	0.00	0.00	0.00
210.0	Gain on Reacquired Pref Stock	0.00	0.00	0.00
	Net Income Transferred	12,524,453.05	18,978,453.21	(6,454,000.16)
	Total Unappropriated Retained Earnings	203,343,368.61	190,818,915.56	12,524,453.05
216.1	Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
418.1	Equity Earnings of Subsidiary Co	0.00	0.00	0.00
	Total Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
	Total Other Retained Earnings Accounts	0.00	0.00	(0.00)
	TOTAL RETAINED EARNINGS	**203,343,368.61**	**190,818,915.56**	12,524,453.05

Final

GLR7210V

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - April, 2014

05/12/14 07:45

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	9,483,918.12	(2,101,586.69)	(9.12)	0.00	1,486,066,574.19
	TOTAL PRODUCTION	1,478,684,251.88	9,483,918.12	(2,101,586.69)	(9.12)	0.00	1,486,066,574.19
101/106	TRANSMISSION	503,165,571.80	3,931,214.88	(63,568.20)	0.00	0.00	507,033,218.48
101/106	DISTRIBUTION	733,776,590.81	10,008,907.67	(2,497,043.62)	0.00	0.00	741,288,454.86
	TOTAL (ACCOUNTS 101 & 106)	2,715,626,414.49	23,424,040.67	(4,662,198.51)	(9.12)	0.00	2,734,388,247.53
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	962,943.15	0.00	7,242,092.32
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	2,721,905,563.66	23,424,040.67	(4,662,198.51)	962,934.03	0.00	2,741,630,339.85
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	CONSTRUCTION WORK IN PROGRESS:						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		40,298,604.42				
107000X	TRANSFERS		(23,424,040.67)				
107000X	END. BAL.		16,874,563.75				145,473,711.94
	TOTAL ELECTRIC UTILITY PLANT	2,857,910,670.58	40,298,604.42	(4,662,198.51)	962,934.03	0.00	2,894,510,010.52
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	5,529,435.74	0.00	0.00	(0.03)	0.00	5,529,435.71

Prepared by: PSnVision Report GLS7210V
Reviewer: Cassie Crites – Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

Final

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - April, 2014

GLR7410V 05/12/14

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	18,870,459.72	(2,101,586.69)	(372,218.47)	0.00	615,900,781.45
1080001/11	TRANSMISSION	161,537,795.16	2,892,853.62	(63,568.20)	(122,014.77)	0.00	164,245,065.81
1080001/11	DISTRIBUTION	192,744,660.64	8,428,628.22	(2,497,043.62)	(613,782.38)	0.00	198,062,462.86
1080013	PRODUCTION	(3,620,015.26)	0.00	0.00	0.00	(175,435.05)	(3,795,450.31)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698.85)	0.00	0.00	0.00	(3,053.95)	(29,752.80)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(1,802,817.06)	1,108,015.62	(9,015,053.96)
	TOTAL (108X accounts)	**941,819,616.07**	**30,191,941.56**	**(4,662,198.51)**	**(2,910,832.68)**	**929,526.62**	**965,368,053.06**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	442,289.96	0.00	0.00	84,795.27	10,956,436.10
1110001	TRANSMISSION	1,607,792.68	191,246.75	0.00	0.00	0.00	1,799,039.43
1110001	DISTRIBUTION	7,182,584.75	503,395.53	0.00	0.00	0.00	7,685,980.28
	TOTAL (111X accounts)	**19,219,728.30**	**1,136,932.24**	**0.00**	**0.00**	**84,795.27**	**20,441,455.81**
1011006	CAPITAL LEASES	1,669,467.09	0.00	0.00	0.00	(39,285.35)	1,630,181.74
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**962,908,811.46**	**31,328,873.80**	**(4,662,198.51)**	**(2,910,832.68)**	**975,036.54**	**987,639,690.61**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	214,955.75	2,223.24	0.00	0.00	0.00	217,178.99
1240027	Other Property - RWIP	(3,400.00)	0.00	0.00	0.00	0.00	(3,400.00)
	TOTAL NONUTILITY PLANT	**211,555.75**	**2,223.24**	**0.00**	**0.00**	**0.00**	**213,778.99**

Prepared By: PSnVision Report GLS7410V
Reviewer: Cassie Crites – Prop Acctg. Canton
Sources of Info: PowerPlant Reports and PS GL

AEP
AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

June 24, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed May 2014 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-9	Income Statement
1-3	Details of Operating Revenues
4-7	Operating Expenses – Functional Expenses
8-9	Detail Statement of Taxes
Balance Sheet:	
10	Balance Sheet – Assets & Other Debits
10-12	Balance Sheet – Liabilities & Other Credits
11-12	Deferred Credits
12	Statement of Retained Earnings
Utility Property:	
13-14	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J Frantz

Brian J. Frantz
Manager –Regulated Accounting

American Electric Power

INCOME STATEMENT

GLS8016
YTD May 2014
06/09/2014 16:14

Layout: GLS8016

09B V2014-05-31		Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	58,101,877	57,267,319	834,558	0
4400002		Residential Sales-W/O Space Ht	23,313,504	22,896,776	416,729	0
4400005		Residential Fuel Rev	34,585,875	34,585,875	0	0
	A	**Revenue - Residential Sales**	**116,001,256**	**114,749,970**	**1,251,286**	-
4420001		Commercial Sales	32,285,757	31,839,076	446,682	0
4420006		Sales to Pub Auth - Schools	6,021,533	5,940,441	81,091	0
4420007		Sales to Pub Auth - Ex Schools	6,003,814	5,916,373	87,441	0
4420013		Commercial Fuel Rev	17,801,559	17,801,559	0	0
	A	**Revenue - Commercial Sales**	**62,112,663**	**61,497,449**	**615,214**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	26,562,890	26,221,663	341,227	0
4420004		Ind Sales-NonAffil(Incl Mines)	13,156,259	12,900,302	255,958	0
4420016		Industrial Fuel Rev	37,191,188	37,191,188	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**76,910,337**	**76,313,153**	**597,185**	-
		Revenue - Industrial Sales	**76,910,337**	**76,313,153**	**597,185**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	612,484	599,194	13,289	0
4440002		Public St & Hwy Light Fuel Rev	137,398	137,398	0	0
	A	**Revenue - Other Retail Sales**	**749,882**	**736,592**	**13,289**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**255,774,138**	**253,297,164**	**2,476,974**	-
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	14,861,451
4561033		PJM NITS Revenue - Affiliated	5,927,747	0	0	15,115,118
4561034		PJM TO Adm Serv Rev - Aff	0	0	0	239,158
4561035		PJM Affiliated Trans NITS Cost	(5,910,528)	0	(15,097,899)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(239,158)	0
4561059		Affil PJM Trans Enhancmnt Rev	54,482	0	0	135,716
4561060		Affil PJM Trans Enhancmnt Cost	(54,328)	0	(135,562)	0
4561062		PROVISION RTO Cost - Affi	(317,741)	0	(317,741)	0
4561063		PROVISION RTO Rev Affiliated	(91,692)	0	0	(91,692)
	B	**Revenue - Transmission-Affiliated**	**(392,059)**	-	**(15,790,360)**	**30,259,751**
4470150		Transm Rev -Dedic Whlsl/Muni	24,106	0	(279,383)	303,489
4470206		PJM Trans loss credits-OSS	1,218,588	0	1,218,588	0
4470207		PJM transm loss charges - LSE	(10,366,779)	0	(10,366,779)	0
4470208		PJM Transm loss credits-LSE	1,640,157	0	1,640,157	0
4470209		PJM transm loss charges-OSS	(9,354,080)	0	(9,354,080)	0
4561002		RTO Formation Cost Recovery	1,992	0	(58,585)	60,576
4561003		PJM Expansion Cost Recov	33,932	0	(36,455)	70,388
4561005		PJM Point to Point Trans Svc	305,879	0	305,879	0
4561006		PJM Trans Owner Admin Rev	111,706	0	0	111,706
4561007		PJM Network Integ Trans Svc	6,036,343	0	0	6,036,343
4561019		Oth Elec Rev Trans Non Affil	26,348	0	0	26,348
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	1,703	0	0	1,703
4561029		PJM NITS Revenue Whsl Cus-NAff	1,123,666	0	0	1,123,666
4561030		PJM TO Serv Rev Whls Cus-NAff	16,854	0	0	16,854
4561058		NonAffil PJM Trans Enhncmt Rev	139,592	0	0	139,592
4561061		NAff PJM RTEP Rev for Whsl-FR	10,089	0	0	10,089
4561064		PROVISION RTO Rev WhslCus-NAf	(5,801)	0	0	(5,801)
4561065		PROVISION RTO Rev - NonAff	(33,710)	0	0	(33,710)
	A	**Revenue - Transmission-NonAffiliated**	**(9,069,417)**	-	**(16,930,658)**	**7,861,241**
		Revenue - Transmission	**(9,461,476)**	-	**(32,721,018)**	**38,120,992**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	262	0	262	0
4470128		Sales for Res-Aff Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,479,520**	-	**5,479,520**	-
4470002		Sales for Resale - NonAssoc	3,131	0	3,131	0
4470006		Sales for Resale-Bookout Sales	7,930,980	0	7,930,980	0
4470010		Sales for Resale-Bookout Purch	(9,066,659)	0	(9,066,659)	0
4470027		Whsl/Muni/Pb Ath Fuel Rev	1,206,749	0	1,206,749	0
4470028		Sale/Resale - NA - Fuel Rev	149,457	0	149,457	0
4470033		Whsl/Muni/Pub Auth Base Rev	2,270,566	0	2,270,566	0
4470066		PWR Trdng Trans Exp-NonAssoc	(39)	0	(39)	0
4470081		Financial Spark Gas - Realized	13,745	0	13,745	0
4470082		Financial Electric Realized	2,375,150	0	2,375,150	0
4470089		PJM Energy Sales Margin	78,652,960	0	78,652,960	0
4470093		PJM Implicit Congestion-LSE	(16,026,154)	0	(16,026,154)	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD May 2014
06/09/2014 18:14

Layout: GLS8016

09B V2014-05-31		Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
4470098		PJM Oper Reserve Rev-OSS	(2,718,716)	0	(2,718,716)	0
4470099		Capacity Cr Net Sales	207,532	0	207,532	0
4470100		PJM FTR Revenue-OSS	621,811	0	621,811	0
4470101		PJM FTR Revenue-LSE	6,838,276	0	6,838,276	0
4470103		PJM Energy Sales Cost	76,124,484	0	76,124,484	0
4470106		PJM Pt2Pt Trans Purch-NonAff	(27)	0	(27)	0
4470107		PJM NITS Purch-NonAff	21,032	0	21,032	0
4470109		PJM FTR Revenue-Spec	(66,988)	0	(66,988)	0
4470110		PJM TO Admin Exp NonAff	34,880	0	34,880	0
4470112		Non-Trading Bookout Sales-OSS	4,943	0	4,943	0
4470115		PJM Meter Corrections-OSS	(6,017)	0	(6,017)	0
4470116		PJM Meter Corrections-LSE	42,029	0	42,029	0
4470124		PJM Incremental Spot-OSS	1	0	1	0
4470126		PJM Incremental Imp Cong-OSS	(23,115,510)	0	(23,115,510)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	(315,496)	0	(315,496)	0
4470144		Realiz Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim Margin Reclass	(175)	0	(175)	0
4470168		Interest Rate Swaps-Power	(9,493)	0	(9,493)	0
4470170		Non-ECR Auction Sales-OSS	1,419,803	0	1,419,803	0
4470174		PJM Whlse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	178,231	0	178,231	0
4470176		OSS Sharing Reclass-Reduction	(178,231)	0	(178,231)	0
4470180		Trading intra-book Reclass	(119,635)	0	(119,635)	0
4470181		Auction intra-book Reclass	119,635	0	119,635	0
4470202		PJM OpRes-LSE-Credit	392,473	0	392,473	0
4470203		PJM OpRes-LSE-Charge	(4,540,155)	0	(4,540,155)	0
4470204		PJM Spinning-Credit	(0)	0	(0)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,181	0	28,181	0
4470220		PJM Regulation - OSS	97,425	0	97,425	0
4470221		PJM Spinning Reserve - OSS	8,611	0	8,611	0
4470222		PJM Reactive - OSS	261,056	0	261,056	0
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	(10,423)	0	(10,423)	0
5550080		PJM Hourly Net Purch -FERC	(18,035,183)	0	(18,035,183)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**104,795,655**	-	**104,795,655**	-
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**110,275,375**	-	**110,275,375**	-
4470074		Sale for Resale-Aff-Trnf Price	0	0	187,578,514	0
4540001		Rent From Elect Property - Af	108,645	323,909	0	0
4560001		Oth Elect Rev - Affiliated	4,906	0	4,906	0
	B	**Revenue - Other Ele-Affiliated**	**113,551**	**323,909**	**187,583,420**	-
4500000		Forfeited Discounts	1,797,659	1,797,659	0	0
4510001		Misc Service Rev - Nonaffil	149,737	144,089	0	5,648
4540002		Rent From Elect Property-NAC	60,264	1,050	56,989	2,225
4540005		Rent from Elec Prop-Pole Attch	2,047,823	2,047,823	0	0
4560007		Oth Elect Rev - DSM Program	2,598,446	2,598,446	0	0
		Revenue - Other Ele-NonAffiliated	**6,653,929**	**6,589,067**	**56,989**	**7,873**
		Revenue - Gas	-	-	-	-
4118002		Comp Allow Gains Title IV SO2	383	0	383	0
4118004		Comp Allow Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,916**	-	**8,916**	-
	A	**Revenue - Other Ele-NonAffiliated**	**6,662,845**	**6,589,067**	**65,905**	**7,873**
		Revenue - Other Opr Electric	**6,776,396**	**6,912,976**	**187,649,325**	**7,873**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	14,000	13,500	500	0
4180003		Non-Opratng Rntal Inc-Maint	(16)	0	(16)	0
4180005		Non-Opratng Rntal Inc-Depr	(2,779)	0	0	(2,779)
	D	**Non-Operating Rental Income - NonAffiliated**	**11,205**	**13,500**	**484**	**(2,779)**
		Non-Operating Rental Income	**11,205**	**13,500**	**484**	**(2,779)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc Rents	2,197	295	1,718	184

American Electric Power

INCOME STATEMENT

GLS8016
YTD May 2014
06/09/2014 18.14

Layout: GLS8016

09B V2014-05-31	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
4210007	Misc Non-Op Inc - NonAsc - Oth	36,409	330	36,079	0
D	**Non-Operating Misc Income - NonAffiliated**	**38,606**	**625**	**37,797**	**184**
	Non-Operating Misc Income	**38,606**	**625**	**37,797**	**184**
4540004	Rent From Elect Prop-ABD-Nonaf	30,691	30,691	0	0
4560015	Other Electric Revenues - ABD	106,078	106,126	0	1,952
D	**Associated Business Development Income**	**138,768**	**136,816**	**-**	**1,952**
	Revenue - Other Opr - Other	**188,580**	**150,941**	**38,281**	**(643)**
=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***188,580***	***150,941***	***38,281***	***(643)***
	Revenue - Other Operating	**6,964,976**	**7,063,917**	**187,687,606**	**7,231**
A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
B	**Provision for Rate Refund - Affiliated**	-	-	-	-
	Provision for Rate Refund	-	-	-	-
4210031	Pwr Sales Outside Svc Territy	18,427	0	18,427	0
4210032	Pwr Purch Outside Svc Territy	(258)	0	(258)	0
A	**Revenue - Power Sales**	**18,170**	**-**	**18,170**	**-**
	TOTAL OPERATING REVENUES	**383,571,182**	**260,361,081**	**267,737,106**	**38,128,223**
=(A)	*Memo: G/T/D Revenue*	*358,181,590*	*259,886,231*	*90,426,245*	*7,869,114*
=(B)	*Memo: Other Affiliated Revenue*	*5,201,011*	*323,909*	*177,272,580*	*30,259,751*
=(C)	*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)	*Memo: Revenue-Oth Opr-Oth Non*	*188,580*	*150,941*	*38,281*	*(643)*
	Memo: Total Operating Revenues	***383,571,182***	***260,361,081***	***267,737,106***	***38,128,223***
=(E)=(B)+(C)	***Memo: Affiliated Revenue***	***5,201,011***	***323,909***	***177,272,580***	***30,259,751***
=(F)=(D)+(A)	***Memo: Non-Affiliated Revenue***	***358,370,170***	***260,037,172***	***90,464,526***	***7,868,472***
	Memo: Total Operating Revenues	***383,571,182***	***260,361,081***	***267,737,106***	***38,128,223***
	FUEL EXPENSES				
5010000	Fuel	80,196	0	80,196	0
5010001	Fuel Consumed	119,448,518	0	119,448,518	0
5010003	Fuel - Procure Unload & Handle	5,497,261	0	5,497,261	0
5010013	Fuel Survey Activity	(734,602)	0	(734,602)	0
5010019	Fuel Oil Consumed	3,104,166	0	3,104,166	0
5010027	Gypsum handling/disposal costs	168,900	0	168,900	0
5010028	Gypsum Sales Proceeds	(339,777)	0	(339,777)	0
5470004	Fuel - Gas Turb - Purch / Hand	(218)	(8)	(204)	(6)
	Fuel Expense Total	**127,224,444**	**(8)**	**127,224,458**	**(6)**
5010005	Fuel - Deferred	(12,963,611)	0	(12,963,611)	0
	Deferred Fuel Expense	**(12,963,611)**	**-**	**(12,963,611)**	**-**
	Over Under Fuel Expense				
	Fuel for Electric Generation	**114,260,833**	**(8)**	**114,260,847**	**(6)**
5010029	Gypsum handling/displ-Affiliat	70,605	0	70,605	0
	Fuel from Affiliates for Electric Generation	**70,605**	**-**	**70,605**	**-**
5090000	Allow Consum Title IV SO2	3,945,438	0	3,945,438	0
5090001	Allowance Consumption - NOx	5,280	0	5,280	0
5090005	An NOx Cons Exp	59,490	0	59,490	0
	Allowances - Consumption	**4,010,208**	**-**	**4,010,208**	**-**
5020002	Urea Expense	2,268,235	0	2,268,235	0
5020003	Trona Expense	156,050	0	156,050	0
5020004	Limestone Expense	1,809,947	0	1,809,947	0
5020005	Polymer expense	36,513	0	36,513	0
5020007	Lime Hydrate Expense	6,371	0	6,371	0
	Emissions Control - Chemicals	**4,277,116**	**-**	**4,277,116**	**-**
	Total Fuel for Electric Generation	**122,618,762**	**(8)**	**122,618,776**	**(6)**
	Memo: NonAff Fuel/Allow/Emissions	***122,548,157***	***(8)***	***122,548,171***	***(6)***
5550004	Purchased Power-Pool Capacity	181,949	0	181,949	0
5550005	Purchased Power - Pool Energy	676,093	0	676,093	0
5550027	Purch Pwr-Non-Fuel Portion-Aff	20,287,786	0	20,287,786	0
5550029	Purch Power-Assoc-Trnsfr Price	0	187,578,514	0	0
5550046	Purch Power-Fuel Portion-Affil	27,556,592	0	27,556,592	0
5550101	Purch Power-Pool Non-Fuel -Aff	168,508	0	168,508	0
5550102	Pur Power-Pool NonFuel-OSS-Aff	214,985	0	214,985	0
	Purchased Electricity from AEP - Affiliates	**49,085,913**	**187,578,514**	**49,085,913**	**-**
5550000	Purchased Power	13	0	13	0
5550001	Purch Pwr-NonTrading-Nonassoc	741,762	0	741,762	0
5550032	Gas-Conversion-Mone Plant	3,271	0	3,271	0
5550039	PJM Inadvertent Mtr Res-OSS	(71,227)	0	(71,227)	0
5550040	PJM Inadvertent Mtr Res-LSE	(38,613)	0	(38,613)	0
5550041	PJM Ancillary Serv -Sync	974	0	974	0
5550074	PJM Reactive-Charge	(11,793)	0	(11,793)	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD May 2014
06/09/2014 16:14

Layout: GLS8016

098 V2014-05-31	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
5550076	PJM Black Start-Charge	572,828	0	572,828	0
5550077	PJM Black Start-Credit	(7)	0	(7)	0
5550078	PJM Regulation-Charge	1,365,073	0	1,365,073	0
5550079	PJM Regulation-Credit	(308,135)	0	(308,135)	0
5550083	PJM Spinning Reserve-Charge	1,149,304	0	1,149,304	0
5550084	PJM Spinning Reserve-Credit	(292,276)	0	(292,276)	0
5550090	PJM 30m Suppl Rserv Charge LSE	385,385	0	385,385	0
5550099	PJM Purchases-non-ECR-Auction	1,501,120	0	1,501,120	0
5550100	Capacity Purchases-Auction	35,646	0	35,646	0
5550107	Capacity purchases - Trading	45,663	0	45,663	0
	Purchased Electricity for Resale - NonAffiliated	**5,078,987**	**-**	**5,078,987**	**-**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**54,164,900**	**187,578,514**	**54,164,900**	**-**
	GROSS MARGIN	**186,787,520**	**72,782,575**	**90,953,431**	**38,128,229**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	1,576,196	29	1,576,148	19
5000001	Oper Super & Eng-RATA-Affl	40,462	0	40,462	0
5020000	Steam Expenses	1,024,769	0	1,024,769	0
5050000	Electric Expenses	248,866	0	248,866	0
5060000	Misc Steam Power Expenses	3,435,553	44	3,435,481	28
5060002	Misc Steam Power Exp-Assoc	24,905	0	24,905	0
5060003	Removal Cost Expense - Steam	(77,445)	0	(77,445)	0
5060004	NSR Settlement Expense	(1,427)	0	(1,427)	0
5060025	Misc Stm Pwr Exp Environmental	(9)	0	(9)	0
	Steam Generation Op Exp	**6,271,870**	**73**	**6,271,750**	**47**
5170001	Oper Supervision & Engineering	12	0	12	0
5200000	Steam Expenses	6	2	3	1
	Nuclear Generation Op Exp	**19**	**2**	**16**	**1**
5390000	Misc Hydr Power Generation Exp	1	0	1	0
	Hydro Generation Op Exp	**1**	**0**	**1**	**0**
5490000	Misc Other Pwer Generation Exp	(1,271)	0	(1,271)	0
5560000	Sys Control & Load Dispatching	220,845	(100)	220,862	83
5570000	Other Expenses	718,411	(728)	719,391	(253)
5570007	Other Pwr Exp - Wholesale RECs	10,715	10,715	0	0
5757000	PJM Admin-MAM&SC- OSS	230,500	0	230,500	0
5757001	PJM Admin-MAM&SC- Internal	333,491	0	333,491	(0)
	Other Generation Op Exp	**1,512,691**	**9,887**	**1,502,974**	**(170)**
5600000	Oper Supervision & Engineering	438,635	1,046	2,130	435,458
5611000	Load Dispatch - Reliability	3,772	0	0	3,772
5612000	Load Dispatch-Mntr&Op TransSys	370,704	47	76	370,581
5614000	PJM Admin-SSC&DS-OSS	204,231	0	204,231	0
5614001	PJM Admin-SSC&DS-Internal	301,556	0	301,556	0
5614007	RTO Admin Default LSE	3,874	0	3,539	335
5614008	PJM Admin Defaults OSS	2,417	0	2,417	0
5615000	Reliability,Plng&Stds Develop	46,617	3,707	5,729	37,181
5618000	PJM Admin-RP&SDS-OSS	54,446	0	54,446	0
5618001	PJM Admin-RP&SDS- Internal	78,455	0	78,455	0
5620001	Station Expenses - Nonassoc	109,478	0	0	109,478
5630000	Overhead Line Expenses	83,413	0	0	83,413
5650002	Transmssn Elec by Others-NAC	86,634	0	86,634	0
5650007	Tran Elec by Oth-Aff-Trn Pnce	0	14,861,451	0	0
5650012	PJM Trans Enhancement Charge	1,812,752	0	1,612,752	0
5650015	PJM TO Serv Exp - Aff	17,339	0	17,339	0
5650016	PJM NITS Expense - Affiliated	1,587,589	0	1,587,589	0
5650019	Affil PJM Trans Enhncement Exp	80,605	0	80,605	0
5650020	PROVISION RTO Affl Expense	(155,081)	0	(155,081)	0
5660000	Misc Transmission Expenses	566,487	4,827	6,896	554,764
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	215,264
5757002	SPP Admin-MAM&SC	0	0	0	0
	Transmission Op Exp	**5,494,172**	**14,871,078**	**3,889,313**	**1,810,496**
5800000	Oper Supervision & Engineering	286,781	281,910	1,442	3,429
5810000	Load Dispatching	1,536	1,302	0	234
5820000	Station Expenses	98,777	97,237	0	1,540
5830000	Overhead Line Expenses	367,218	367,335	(135)	18
5840000	Underground Line Expenses	29,534	29,362	126	46
5841000	Oper of Energy Storage Equip	0	0	0	0

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INCOME STATEMENT

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Layout: GLS8016

09B V2014-05-31	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
5850000	Street Lighting & Signal Sys E	58,186	58,186	0	0
5860000	Meter Expenses	351,476	350,255	997	223
5870000	Customer Installations Exp	68,895	68,895	0	0
5880000	Miscellaneous Distribution Exp	1,639,995	1,625,771	2,903	11,321
5890001	Rents - Nonassociated	606,459	606,459	0	0
5890002	Rents - Associated	28,665	28,665	0	0
	Distribution Op Exp	**3,537,521**	**3,515,377**	**5,333**	**16,811**
9010000	Supervision - Customer Accts	126,554	126,480	54	20
9020000	Meter Reading Expenses	1,615	1,381	171	63
9020001	Customer Card Reading	325	97	167	61
9020002	Meter Reading - Regular	184,616	184,616	0	0
9020003	Meter Reading - Large Power	22,814	22,814	0	0
9020004	Read-In & Read-Out Meters	25,132	25,132	0	0
9030000	Cust Records & Collection Exp	150,428	147,291	213	2,924
9030001	Customer Orders & Inquiries	1,057,088	1,056,918	138	32
9030002	Manual Billing	17,501	16,865	5	631
9030003	Postage - Customer Bills	330,201	330,201	0	0
9030004	Cashiering	46,946	46,843	44	59
9030005	Collection Agents Fees & Exp	20,722	20,722	0	0
9030006	Credit & Oth Collection Activi	317,711	317,663	36	12
9030007	Collectors	247,076	247,076	0	0
9030009	Data Processing	70,753	70,740	9	3
9040007	Uncoll Accts - Misc Receivable	(42,615)	(47,340)	4,725	0
9050000	Misc Customer Accounts Exp	12,413	12,413	0	0
9070000	Supervision - Customer Service	69,668	69,666	1	1
9070001	Supervision - DSM	(11)	(4)	(4)	(3)
9080000	Customer Assistance Expenses	203,097	203,092	3	3
9080001	DSM-Customer Advisory Grp	862	862	0	0
9080009	Cust Assistance Expense - DSM	2,176,829	2,176,040	569	220
9090000	Information & Instruct Advrts	52,606	15,963	26,676	9,967
9100000	Misc Cust Svc&Informational Ex	14,085	5,926	6,091	2,068
	Customer Service and Information Op Exp	**5,106,418**	**5,051,459**	**38,896**	**16,063**
9120000	Demonstrating & Selling Exp	7,765	7,765	0	0
9120003	Demo & Selling Exp - Area Dev	(321)	(321)	0	0
	Sales Expenses	**7,444**	**7,444**	-	-
	Memo: Insurance (9240 9250)	**568,521**	**208,197**	**287,087**	**73,237**
9200000	Administrative & Gen Salaries	3,874,307	1,756,878	1,549,657	567,772
9210001	Off Supl & Exp - Nonassociated	320,978	199,314	98,878	22,786
9210003	Office Supplies & Exp - Trnsf	6	6	0	0
9220000	Administrative Exp Trnsf - Cr	(227,050)	(227,050)	(0)	0
9220001	Admin Exp Trnsf to Cnstrction	(176,099)	(176,099)	0	0
9220004	Admin Exp Trnsf to ABD	(1,512)	(623)	0	(889)
9230001	Outside Svcs Empl - Nonassoc	481,332	213,781	198,717	68,835
9230002	Outside Svcs Empl - Assoc	(0)	0	(0)	0
9230003	AEPSC Billed to Client Co	(185,522)	(51,539)	(83,989)	(49,994)
9240000	Property Insurance	195,501	68,993	45,779	80,729
9250000	Injuries and Damages	472,214	338,341	114,519	19,354
9250001	Safety Dinners and Awards	2,672	1,189	1,164	319
9250002	Emp Accdent Prvntion-Adm Exp	4,254	2,830	993	432
9250004	Injuries to Employees	1,075	0	1,075	0
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(126,437)	(117,195)	9,935	(19,178)
9250007	Prsnal Injries&Prop Dmage-Pub	119,597	82	119,510	6
9250010	Frg Ben Loading - Workers Comp	(100,356)	(86,044)	(5,886)	(8,426)
9260000	Employee Pensions & Benefits	2,022	2,022	0	0
9260001	Edit & Print Empl Pub-Salaries	8,760	3,146	3,641	1,974
9260002	Pension & Group Ins Admin	22,225	11,320	9,764	1,141
9260003	Pension Plan	2,072,568	955,672	1,002,893	114,003
9260004	Group Life Insurance Premiums	64,388	26,156	34,042	4,190
9260005	Group Medical Ins Premiums	2,099,654	1,060,649	873,470	165,535
9260006	Physical Examinations	1	0	0	1
9260007	Group L-T Disability Ins Prem	7,312	5,169	1,810	333
9260009	Group Dental Insurance Prem	117,855	60,916	49,094	7,846
9260010	Training Administration Exp	115	43	37	35
9260012	Employee Activities	1,435	523	406	506
9260014	Educational Assistance Pmts	450	450	0	0
9260021	Postretirement Benefits - OPEB	(1,527,181)	(726,935)	(699,152)	(101,094)
9260027	Savings Plan Contributions	937,496	391,112	504,083	42,301
9260036	Deferred Compensation	1,956	1,956	0	0
9260037	Supplemental Pension	100	100	0	0
9260040	SFAS 112 Postemployment Benef	426,707	0	426,707	0

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		Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
9260050	Frg Ben Loading - Pension	(616,876)	(438,048)	(139,632)	(39,196)
9260051	Frg Ben Loading - Grp Ins	(745,711)	(534,960)	(149,144)	(61,608)
9260052	Frg Ben Loading - Savings	(303,663)	(187,317)	(92,043)	(24,304)
9260053	Frg Ben Loading - OPEB	172,628	136,395	19,244	16,988
9260055	IntercoFringeOffset - Don't Use	(730,766)	(163,191)	(501,888)	(65,686)
9260057	Postret Ben Medicare Subsidy	257,829	103,829	144,150	9,850
9260058	Frg Ben Loading - Accrual	(17,547)	3,374	(19,362)	(1,559)
9260060	Amort Post Retirement Benefit	90,258	53,992	29,669	6,597
9270000	Franchise Requirements	58,887	58,887	0	0
9280000	Regulatory Commission Exp	21,415	7,653	8,846	4,916
9280001	Regulatory Commission Exp-Adm	0	0	0	0
9280002	Regulatory Commission Exp-Case	60,214	11,457	41,529	7,228
9301000	General Advertising Expenses	848	298	362	187
9301001	Newspaper Advertising Space	8,442	3,043	3,506	1,893
9301002	Radio Station Advertising Time	3,418	1,237	1,413	768
9301010	Publicity	1,891	674	808	409
9301012	Public Opinion Surveys	15,401	15,398	0	3
9301015	Other Corporate Comm Exp	6,403	4,596	1,257	551
9302000	Misc General Expenses	73,405	31,043	22,192	20,170
9302003	Corporate & Fiscal Expenses	20,004	4,107	14,815	1,081
9302004	Research, Develop&Demonstr Exp	2,695	2,695	0	0
9302458	AEPSC Non Affiliated expenses	(0)	0	(0)	0
9310001	Rents - Real Property	40,676	40,676	0	0
9310002	Rents - Personal Property	102,901	67,458	30,675	4,767
9310004	Rents - Personal Prop - Assoc	704	0	704	0
	Administration & General	**7,414,282**	**2,938,460**	**3,674,248**	**801,573**
4111005	Accretion Expense	401,415	0	401,415	0
	Accretion	**401,415**	-	**401,415**	-
4116000	Gain From Disposition of Plant	(1,675)	(1,675)	0	0
	Loss/(Gain) on Utility Plant	**(1,675)**	**(1,675)**	-	-
9302006	Assoc Bus Dev - Materials Sold	30,899	30,899	0	0
9302007	Assoc Business Development Exp	58,106	41,601	7	16,498
	Associated Business Development Expenses	**89,005**	**72,500**	**7**	**16,498**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4265009	Factored Cust A/R Exp - Affil	390,871	390,871	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	789,767	789,767	0	0
	Opr Exp and Factored A/R	**1,180,638**	**1,180,638**	-	-
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	29,549	10,547	12,819	6,184
	Expense of Non-Utility Operation	**29,549**	**10,547**	**12,819**	**6,184**
4210009	Misc Non-Op Exp - NonAssoc	4,452	916	2,964	573
	Misc NonOp Expenses - NonAssoc	**4,452**	**916**	**2,964**	**573**
4261000	Donations	169,203	100,188	60,886	8,129
	Donation Contributions	**169,203**	**100,188**	**60,886**	**8,129**
4263001	Penalties	62,109	23,921	24,132	14,056
	Provision for Penalties	**62,109**	**23,921**	**24,132**	**14,056**
4264000	Civic & Political Activities	109,673	40,072	44,536	25,064
	Civic & Political Activities	**109,673**	**40,072**	**44,536**	**25,064**
4265002	Other Deductions - Nonassoc	56	12	36	8
4265033	Transition Costs	5,267	0	5,267	0
	Other Deductions	**5,322**	**12**	**5,302**	**8**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**1,560,947**	**1,356,295**	**150,639**	**54,013**
	Operational Expenses	**31,394,108**	**27,820,901**	**15,934,590**	**2,715,332**
5100000	Maint Supv & Engineering	1,629,931	65	1,629,857	9
5110000	Maintenance of Structures	777,468	0	777,468	0
5120000	Maintenance of Boiler Plant	7,301,333	0	7,301,320	13
5130000	Maintenance of Electric Plant	1,304,043	0	1,304,350	(307)
5140000	Maintenance of Misc Steam Plt	679,986	0	679,986	0
	Steam Generation Maintenance	**11,692,760**	**65**	**11,692,980**	**(285)**
5300000	Maint of Reactor Plant Equip	(5)	0	0	(5)
5320009	Security Equipment	(3)	(1)	(1)	(1)
	Nuclear Generation Maintenance	**(8)**	**(1)**	**(1)**	**(6)**
	Hydro Generation Maintenance	-	-	-	-
5530001	Maint of Gen Plant - Gas Turb	(3,063)	0	(640)	(2,423)
	Other Generation Maintenance	**(3,063)**	-	**(640)**	**(2,423)**
5680000	Maint Supv & Engineering	37,235	0	10	37,225

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09B V2014-05-31	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
5690000	Maintenance of Structures	3,422	0	0	3,422
5691000	Maint of Computer Hardware	9,008	10	7	8,991
5692000	Maint of Computer Software	133,717	2,172	0	131,545
5693000	Maint of Communication Equip	6,682	0	0	6,682
5700000	Maint of Station Equipment	334,014	18,182	0	315,832
5710000	Maintenance of Overhead Lines	564,024	(1,833)	51	565,807
5720000	Maint of Underground Lines	66	0	0	66
5730000	Maint of Misc Trnsmssion Plt	120,746	0	0	120,746
	Transmission Maintenance	**1,208,915**	**18,531**	**68**	**1,190,316**
5900000	Maint Supv & Engineering	1,309	1,313	(1)	(3)
5910000	Maintenance of Structures	6,702	6,126	0	576
5920000	Maint of Station Equipment	300,955	298,958	11	1,985
5930000	Maintenance of Overhead Lines	12,891,022	12,888,523	2,576	(78)
5930001	Tree and Brush Control	149,811	149,811	0	0
5930008	Maint Ovh Lines Strm Exp-OvUnd	1,292	1,292	0	0
5930010	Storm Expense Amortization	1,957,685	1,957,685	0	0
5940000	Maint of Underground Lines	32,308	32,308	0	0
5950000	Maint of Lne Trnf,Rglators&Dvi	27,996	27,996	0	0
5960000	Maint of Strt Lghtng & Sgnal S	27,185	27,185	0	0
5970000	Maintenance of Meters	35,016	33,248	0	1,768
5980000	Maint of Misc Distribution Plt	96,733	96,200	0	533
	Distribution Maintenance	**15,528,013**	**15,520,645**	**2,587**	**4,781**
9350001	Maint of Structures - Owned	120,302	117,446	153	2,703
9350002	Maint of Structures - Leased	22,668	21,003	1,078	586
9350003	Maint of Prprty Held Fture Use	451	(1)	454	(1)
9350006	Maint of Carrier Equipment	13	13	0	0
9350012	Maint of Data Equipment	346	0	346	0
9350013	Maint of Cmmncation Eq-Unall	320,881	297,314	23,567	0
9350015	Maint of Office Furniture & Eq	399,058	210,384	188,675	0
9350019	Maint of Gen Plant-SCADA Equ	174	172	2	0
9350023	Site Communications Services	286	0	286	0
9350024	Maint of DA-AMI Comm Equip	8	8	0	0
	Administration & General Maintenance	**864,187**	**646,338**	**214,561**	**3,289**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**29,290,803**	**16,185,578**	**11,909,554**	**1,195,671**
	Total Operational and Maintenance Expenses	**60,684,911**	**44,006,478**	**27,844,144**	**3,911,003**
4040001	Amort. of Plant	1,431,901	633,831	556,922	241,148
4060001	Amort of Plt Acq Adj	16,090	0	0	16,090
	DDA Amortization	**1,447,991**	**633,831**	**556,922**	**257,238**
4073000	Regulatory Debits	120,453	0	0	120,453
	DDA Regulatory Debits	**120,453**	-	-	**120,453**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**1,568,444**	**633,831**	**556,922**	**377,690**
4030001	Depreciation Exp	36,992,691	10,537,063	22,848,017	3,607,611
	DDA Depreciation	**36,992,691**	**10,537,063**	**22,848,017**	**3,607,611**
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	202,333	0	202,333	0
	DDA Asset Retirement Obligation	**202,333**	-	**202,333**	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**37,195,024**	**10,537,063**	**23,050,350**	**3,607,611**
	Depreciation and Amortization	**38,763,468**	**11,170,894**	**23,607,272**	**3,985,301**
	Franchise Taxes	-	-	-	-
408100613	State Gross Receipts Tax	(5,942)	1	(5,943)	0
408100614	State Gross Receipts Tax	25,223	0	25,223	0
	Revenue-kWhr Taxes	**19,281**	**1**	**19,280**	-
4081002	FICA	1,719,384	705,316	936,540	77,528
4081003	Federal Unemployment Tax	18,148	7,878	9,349	921
4081007	State Unemployment Tax	57,924	19,787	35,828	2,308
4081033	Fringe Benefit Loading - FICA	(546,063)	(336,115)	(165,128)	(44,820)
4081034	Fringe Benefit Loading - FUT	(3,756)	(2,304)	(1,221)	(231)
4081035	Fringe Benefit Loading - SUT	(9,600)	(4,962)	(4,127)	(511)
	Payroll Taxes	**1,236,038**	**389,601**	**811,241**	**35,196**
408102014	State Business Occup Taxes	1,655,238	0	1,655,238	0
	Capacity Taxes	**1,655,238**	-	**1,655,238**	-
408100509	Real & Personal Property Taxes	3,975	3,907	0	69
408100510	Real Personal Property Taxes	131	131	0	0
408100512	Real Personal Property Taxes	1,349,282	112,328	1,209,471	27,484
408100513	Real Personal Property Taxes	4,263,050	2,497,185	375,915	1,389,950

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INCOME STATEMENT

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05B V2014-05-31	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
408102913	Real-Pers Prop Tax-Cap Leases	1,038	790	68	180
408102914	Real-Pers Prop Tax-Cap Leases	8,955	6,760	520	1,675
408103613	Real Prop Tax-Cap Leases	(1,473)	(1,473)	0	0
408103614	Real Prop Tax-Cap Leases	10,625	10,625	0	0
408200513	Real Personal Property Taxes	23,585	4,030	0	19,555
	Property Taxes	**5,659,168**	**2,634,282**	**1,585,974**	**1,438,913**
408101813	St Publ Serv Comm Tax-Fees	394,268	394,268	0	0
	Regulatory Fees	**394,268**	**394,268**	-	-
408101414	Federal Excise Taxes	986	0	986	0
	Production Taxes	**986**	-	**986**	-
408101714	St Lic Rgstrtion Tax-Fees	200	200	0	0
408101900	State Sales and Use Taxes	(342,470)	(156,655)	(178,775)	(7,040)
408101912	State Sales and Use Taxes	218,039	89,065	119,078	9,896
408101913	State Sales and Use Taxes	1,295	1,295	0	0
408101914	State Sales and Use Taxes	7,384	7,384	0	0
408102214	Municipal License Fees	300	300	0	0
	Miscellaneous Taxes	**(115,253)**	**(58,411)**	**(59,697)**	**2,856**
	Other Non-Income Taxes	**(114,266)**	**(58,411)**	**(58,711)**	**2,856**
	Taxes Other Than Income Taxes	**8,849,727**	**3,359,741**	**4,013,022**	**1,476,965**
	TOTAL OPERATING EXPENSES	**108,298,106**	**58,537,113**	**55,464,438**	**9,373,289**
	Memo: SEC Total Operating Expenses	**285,081,767**	**246,115,619**	**232,248,114**	**9,373,263**
	OPERATING INCOME	**78,489,414**	**14,245,462**	**35,468,993**	**28,754,960**
	NON OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	18,825	7,252	11,113	460
	Interest & Dividend NonAffiliated	**18,825**	**7,252**	**11,113**	**460**
4190001	Interest Inc - Assoc Non CBP	11,344	11,344	0	0
4190005	Interest Income - Assoc CBP	9,980	1,121	(24,663)	33,523
	Interest & Dividend Affiliated	**21,324**	**12,464**	**(24,663)**	**33,523**
	Total Interest & Dividend Income	**40,149**	**19,716**	**(13,550)**	**33,983**
4210030	Carrying Charges	26,758	0	0	26,758
	Interest & Dividend Carrying Charge	**26,758**	-	-	**26,758**
	Memo: Total Interest & Dividend Income w/ Carrying	**66,907**	**19,716**	**(13,550)**	**60,740**
4191000	Allw Oth Fnds Usd Drng Cnstr	2,343,506	211,575	1,490,320	641,611
	AFUDC	**2,343,506**	**211,575**	**1,490,320**	**641,611**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
	Interest LTD IPC	-	-	-	-
4300001	Interest Exp - Assoc Non-CBP	437,500	173,902	128,704	134,894
	Interest LTD Notes Payable - Affiliated	**437,500**	**173,902**	**128,704**	**134,894**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	14,166,128	5,630,894	4,167,392	4,367,842
	Interest LTD Senior Unsecured	**14,166,128**	**5,630,894**	**4,167,392**	**4,367,842**
4270012	PCRB Interest Exp-Assoc	11,344	11,344	0	0
	Interest LTD Other - Affil	**11,344**	**11,344**	-	-
4270005	Int on LTD - Other LTD	1,207,292	1,213,889	(6,597)	0
	Interest LTD Other - NonAffil	**1,207,292**	**1,213,889**	**(6,597)**	-
	Interest on Long-Term Debt	**15,822,263**	**7,030,029**	**4,289,498**	**4,502,737**
4300003	Int to Assoc Co - CBP	24,613	2,864	143,683	(121,935)
	Interest STD - Affil	**24,613**	**2,864**	**143,683**	**(121,935)**
4310007	Lines Of Credit	318,713	129,459	160,278	28,975
	Interest STD - NonAffil	**318,713**	**129,459**	**160,278**	**28,975**
	Interest on Short Term Debt	**343,326**	**132,324**	**303,961**	**(92,959)**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	196,328	78,038	57,756	60,534
	Amort of Debt Disc. Prem & Exp	**196,328**	**78,038**	**57,756**	**60,534**
4281004	Amrtz Loss Reqrired Debt-Dbnt	14,020	5,573	4,124	4,323
	Amort Loss on Reacquired Debt	**14,020**	**5,573**	**4,124**	**4,323**
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	67,520	20,228	41,474	5,819
4310002	Interest on Customer Deposits	11,301	11,301	0	0
4310023	Interest Expense - State Tax	1,095	545	523	27
	Other Interest - NonAffil	**79,916**	**32,073**	**41,997**	**5,846**
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(1,209,164)	(108,486)	(771,452)	(329,225)

American Electric Power

INCOME STATEMENT

GLS8016
YTD May 2014
06/08/2014 18:14

Layout: GLS8016

09B V2014-05-31	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD May 2014	Kentucky Power Company - Distribution 110 Actual YTD May 2014	Kentucky Power Company - Generation 117 Actual YTD May 2014	Kentucky Power Company - Transmission 180 Actual YTD May 2014
	AFUDC-Borrowed Funds	(1,209,164)	(108,486)	(771,452)	(329,225)
	Total Interest Charges	15,246,689	7,169,551	3,925,884	4,151,254
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	65,653,138	7,307,203	33,039,879	25,306,057
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	20,867,168	3,550,029	10,268,131	7,049,008
4092001	Inc Tax, Oth Inc&Ded-Federal	(263,992)	(178,974)	(58,784)	(26,234)
	Federal Current Income Tax	20,603,176	3,371,055	10,209,347	7,022,774
4101001	Prov Def I/T Utl Op Inc-Fed	21,730,081	2,056,892	18,061,604	1,611,585
4102001	Prov Def I/T Oth I&D - Federal	243,355	156,356	57,755	29,244
4111001	Prv Def I/T-Cr Utl Op Inc-Fed	(21,881,172)	(3,210,721)	(18,067,294)	(603,156)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(20,438)	0	(20,438)	0
	Federal Deferred Income Tax	71,826	(997,474)	31,827	1,037,673
4114001	ITC Adj Utility Oper - Fed	(40,016)	(6,300)	(9,630)	(24,086)
	Federal Investment Tax Credits	(40,016)	(6,300)	(9,630)	(24,086)
	Federal Income Taxes	20,634,986	2,367,281	10,231,344	8,036,361
409100214	Income Taxes UOI - State	3,604,332	333,835	2,055,471	1,215,026
409200214	Inc Tax Oth Inc Ded - State	(45,821)	(31,064)	(10,203)	(4,553)
	State Current Income Tax	3,558,511	302,771	2,045,268	1,210,473
4111002	Prv Def I/T-Cr UtlOpInc-State	(203,840)	0	(203,840)	0
	State Deferred Income Tax	(203,840)	-	(203,840)	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	3,354,671	302,771	1,841,428	1,210,473
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	23,989,657	2,670,052	12,072,772	9,246,833
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	41,663,481	4,637,151	20,967,107	16,059,224
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	41,663,481	4,637,151	20,967,107	16,059,224
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	41,663,481	4,637,151	20,967,107	16,059,224
	NET INCOME (LOSS) NODE before PS	41,663,481	4,637,151	20,967,107	16,059,224
	Double Check on Net Income Node after PS	0	(0)	(0)	-

Reserved Section

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AMERICAN ELECTRIC POWER COMPANY
GLS8216
YTD May 2014
08/10/2014 13:28

BALANCE SHEET

Layout : GLS8216

09B V2014-05- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216 YTD May 2014	Kentucky Power Company - 110 YTD May 2014	Kentucky Power Company - Generation 117 YTD May 2014	Kentucky Power Company - 180 YTD May 2014
ASSETS				
Cash and Cash Equivalents	778,467	778,467	0	0
Other Cash Deposits	0	0	0	0
Customers	17,395,021	13,288,848	3,485,982	620,191
Accrued Unbilled Revenues	(9,330,035)	(9,721,102)	391,067	0
Miscellaneous Accounts Receivable	23,495,246	5,758,425	62,330,489	8,359,259
Allowances for Uncollectible Accounts	(41,850)	(30,222)	(11,628)	0
Accounts Receivable	31,518,382	9,295,949	66,195,910	8,979,451
Advances to Affiliates	0	0	0	0
Fuel, Materials and Supplies	73,423,728	2,468,006	70,034,383	921,339
Risk Management Contracts - Current	2,531,030	1,773	2,529,257	0
Margin Deposits	782,233	15,484	766,748	0
Unrecovered Fuel - Current	10,112,973	0	10,112,973	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	1,781,289	1,480,083	242,753	58,453
TOTAL CURRENT ASSETS	120,928,102	14,039,763	149,882,024	9,959,243
Electric Production	1,064,287,628	748,237,223	1,496,098,057	508,817,898
Electric Transmission	512,264,012	0	0	0
Electric Distribution	703,144,021	0	0	0
General Property, Plant and Equipment	478,986,958	199,571	4,169,386	1,160,479
Construction Work-In-Progress	150,183,144	15,427,564	94,524,911	40,230,670
TOTAL PROPERTY, PLANT and EQUIPMENT	2,908,865,758	763,864,357	1,594,792,354	550,209,047
less: Accumulated Depreciation and Amortization	(974,604,994)	(239,586,035)	(565,497,114)	(169,521,845)
NET PROPERTY, PLANT and EQUIPMENT	1,934,260,764	524,278,322	1,029,295,240	380,687,202
Net Regulatory Assets	217,176,959	102,344,740	59,164,213	55,668,006
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	1,636,577	61	1,636,516	0
Employee Benefits and Pension Assets	13,446,004	(1,134,448)	14,279,430	301,022
Other Non Current Assets	11,844,100	4,930,232	4,391,450	2,522,419
TOTAL OTHER NON-CURRENT ASSETS	244,103,641	106,140,586	79,471,609	58,491,447
TOTAL ASSETS	2,299,292,507	644,458,671	1,258,648,872	449,137,891
LIABILITIES				
Accounts Payable	71,714,145	59,230,784	61,154,275	4,282,012
Advances from Affiliates	23,101,667	(4,492,466)	152,103,800	(124,509,668)
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	200,000,000	0	200,000,000	0
Long-Term Debt Due Within One Year - Affiliated	0	0	0	0
Risk Management Liabilities	903,572	0	903,572	0
Accrued Taxes	27,816,903	8,124,017	5,733,899	13,958,986
Memo: Property Taxes	13,577,953	6,136,655	3,656,072	3,785,226
Accrued Interest	11,445,504	4,542,151	3,398,963	3,504,391
Risk Management Collateral	315,051	0	315,051	0
Utility Customer Deposits	24,426,896	24,426,896	0	0
Deposits - Customer and Collateral	24,741,947	24,426,896	315,051	0
Over-Recovered Fuel Costs - Current	0	0	0	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,166,220	519,060	503,221	143,939
Tax Collections Payable	2,595,075	2,137,426	419,636	38,012
Revenue Refunds - Accrued	1,119,596	0	0	1,119,596
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	878,704	340,377	495,035	43,292
Accrued Rents	1,866	1,866	0	0

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD May 2014
06/10/2014 13:28

Layout : GLS8216

09B V2014-05-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD May 2014	Kentucky Power Company - 110 YTD May 2014	Kentucky Power Company - Generation 117 YTD May 2014	Kentucky Power Company - 180 YTD May 2014
	Accrued ICP	3,178,455	1,225,743	1,833,070	119,643
	Accrued Vacations	5,666,345	2,177,175	3,217,932	271,238
	Misc Employee Benefits	1,344,189	515,024	809,497	19,668
	Payroll Deductions	223,313	99,715	109,353	14,246
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	750,834	326,006	404,320	20,508
2530022	Customer Advance Receipts	1,320,815	1,320,815	0	0
	Customer Advance	1,320,815	1,320,815	0	0
2420511	Control Cash Disburse Account	1,528,211	1,528,211	0	0
	Control Cash Disbursement Account	1,528,211	1,528,211	0	0
	JMG Liability	0	0	0	0
2420088	Econ. Development Fund Curr	291,250	0	291,250	0
2420506	Est Financing Cost - Bonds	(17,998)	0	(17,998)	0
2420512	Unclaimed Funds	4,128	4,128	0	0
2420542	Acc Cash Franchise Req	96,934	96,934	0	0
242059214	Sales Use Tax - Lease Equip	3,181	1,331	151	1,699
2420643	Accrued Audit Fees	(17,590)	(9,655)	(1,851)	(6,074)
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	246,141	0	246,141	0
2530050	Deferred Rev - Pole Attachments	94,125	94,125	0	0
2530112	Other Deferred Credits-Curr	221,616	0	221,616	0
2530124	Contr In Aid of Constr Advance	104,254	104,254	0	0
2530177	Deferred Rev-Bonus Lease Curr	431,564	0	431,564	0
	Misc Current and Accrued Liabilities	2,011,934	291,106	1,725,202	(4,375)
	Current Other and Accrued Liabilities	20,619,337	9,963,465	9,014,043	1,641,829
	Other Current Liabilities	**21,785,557**	**10,482,525**	**9,517,264**	**1,785,767**
	TOTAL CURRENT LIABILITIES	**381,509,294**	**102,313,908**	**433,126,825**	**(100,978,512)**
	Long-Term Debt - Affiliated	**20,000,000**	**7,949,800**	**5,883,600**	**6,166,600**
	Long-Term Debt - Non Affiliated	**530,000,000**	**210,669,700**	**155,915,400**	**163,414,900**
	Long-Term Debt - Premiums and Discounts Unamort	(541,856)	(215,382)	(159,403)	(167,071)
	Memo - LTD NonAffiliated and Premiums	*529,458,144*	*210,454,318*	*155,755,997*	*163,247,829*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	710,805	412	710,393	0
2440022	L/T Liability MTM Collateral	(6,270)	0	(6,270)	0
	Long-Term Risk Management Liabilities - MTM	704,535	412	704,123	0
	Long-Term Risk Management Liabilities	**704,535**	**412**	**704,123**	**0**
	Deferred Income Taxes	**554,883,503**	**168,069,478**	**267,792,614**	**119,021,410**
	Deferred Investment Tax Credits	**85,731**	**17,865**	**28,198**	**39,669**
	Regulatory Liabilities and Deferred Credits	**22,576,471**	(31,524,661)	**60,544,649**	(6,443,517)
	Memo - Reg Liab and Def ITC	*22,662,203*	*(31,506,796)*	*60,572,847*	*(6,403,848)*
	Asset Retirement Obligation	**20,691,638**	**62,418**	**20,629,220**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**8,008,954**	**3,190,954**	**4,721,472**	**96,529**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Rede	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	3,713,476	1,438,545	1,804,477	470,454
	Def Credits - Income Tax	683,714	362,465	278,593	42,656
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	117,290	117,290	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	5,607	0	5,607	0
2530067	IPP - System Upgrade Credits	272,489	0	0	272,489
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	154,238	154,238	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	97,525	0	0	97,525
2530178	Deferred Rev-Bonus Lease NC	1,690,293	0	1,690,293	0
	Def Credits - Other	2,220,153	154,238	1,695,900	370,015
	Total Other Deferred Credits	2,337,443	271,528	1,695,900	370,015
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	873,750	0	873,750	0

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AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD May 2014
06/10/2014 12:28

Layout : GLS8216

09B V2014-05~ Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD May 2014	Kentucky Power Company - 110 YTD May 2014	Kentucky Power Company - Generation 117 YTD May 2014	Kentucky Power Company - 180 YTD May 2014
Other Non-Current Liabilities	8,719,026	2,072,538	5,763,364	883,125
TOTAL NON-CURRENT LIABILITIES	1,165,128,005	360,293,123	521,823,236	283,011,645
TOTAL LIABILITIES	1,546,637,297	462,607,030	954,950,061	182,033,133
Cumulative Pref Stocks of Subs - Not subject Mand Redem	0	0	0	0
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS' EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	517,459,453	106,025,371	327,394,246	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	191,354,405	53,500,275	(27,512,991)	165,367,121
Accumulated Other Comprehensive Income (Loss)	(6,608,649)	(78,055)	(6,470,047)	(60,547)
TOTAL SHAREHOLDERS' EQUITY	752,655,209	181,851,640	303,698,811	267,104,758
Memo: Total Equity	752,655,209	181,851,640	303,698,811	267,104,758
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	2,299,292,507	644,458,671	1,258,648,872	449,137,891
out-of-balance	(0)	0	0	(0)

Reserved Section

Kentucky Power Corp Consol
Comparative Balance Sheet
May 31, 2013

Run Date: 06/11/2013 13:44

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V
KYP_CORP_C(V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS

	Month End Balances 2013	December Balances Last Year	Variance $
ASSETS			
PRODUCTION	559,842,291.84	558,934,668.00	907,623.84
TRANSMISSION	491,085,168.92	490,152,082.00	933,086.92
DISTRIBUTION	668,564,116.62	652,615,328.83	15,948,787.79
GENERAL	59,674,235.77	57,451,300.18	2,222,935.59
CONSTRUCTION WORK IN PROGRESS	47,898,281.42	44,281,291.91	3,616,989.51
ELECTRIC UTILITY PLANT	**1,827,064,094.57**	**1,803,434,670.92**	**23,629,423.65**
less Accum Provision - Depre, Depl, Amort.	(639,413,620.09)	(624,238,902.51)	(15,174,717.58)
NET ELECTRIC UTILITY PLANT	**1,187,650,474.48**	**1,179,195,768.41**	**8,454,706.07**
Net NonUtility Property	2,656,098.42	5,498,717.60	(2,842,619.18)
Investment in Subsidiary & Associated	0.00	0.00	0.00
Other Investments	258,363.67	260,727.67	(2,364.00)
Other Special Funds	0.00	0.00	0.00
Allowance - NonCurrent	2,361,233.00	2,361,232.37	0.63
Long Term Energy Trading Contracts	4,431,338.56	6,881,654.77	(2,450,316.21)
OTHER PROPERTY AND INVESTMENTS	**9,707,033.65**	**15,002,332.41**	**(5,295,298.76)**
Cash and Cash Equivalents	1,401,481.80	1,925,747.09	(524,265.29)
Advances to Affiliates	19,204,717.01	0.00	19,204,717.01
Acct Rec - Customers	9,926,511.96	12,676,052.64	(2,749,540.68)
Acct Rec - Miscellaneous	4,195,711.76	3,141,697.43	1,054,014.33
Acct Rec - AP for Uncollectible Accounts	(19,505.97)	(141,538.08)	122,032.11
Acct Rec - Associated Companies	5,408,890.11	9,241,088.58	(3,832,198.47)
Fuel Stock	44,020,866.67	69,147,176.47	(25,126,309.80)
Materials and Supplies	21,552,325.87	25,061,279.42	(3,508,953.55)
Accrued Utility Revenues	(5,288,420.30)	816,939.53	(6,105,359.83)
Energy Trading	5,062,534.47	6,174,819.72	(1,112,285.25)
Prepayments	996,461.31	1,569,794.80	(573,333.49)
Other Current Assets	1,535,132.24	1,660,942.94	(125,810.70)
CURRENT ASSETS	**107,996,706.92**	**131,274,000.53**	**(23,277,293.61)**
REGULATORY ASSETS	**215,950,324.08**	**214,900,829.18**	**1,049,494.90**
TOTAL DEFERRED CHARGES	**69,344,932.39**	**78,498,798.33**	**(9,153,865.94)**
TOTAL ASSETS	**1,590,649,471.52**	**1,618,871,728.86**	**(28,222,257.34)**
CAPITALIZATION and LIABILITIES			
COMMON STOCK			
Authorized: 2,000,000 Shares			
Outstanding: 1,009,000 Shares			
Common Stock	50,450,000.00	50,450,000.00	0.00
Premium on Capital Stock	0.00	0.00	0.00
Paid-In-Capital	238,562,663.63	238,341,119.49	221,544.14
Retained Earnings	199,663,094.32	190,818,915.56	8,844,178.76
COMMON SHAREHOLDERS' EQUITY	**488,675,757.95**	**479,610,035.05**	**9,065,722.90**
PS Subject To Mandatory Redemption	0.00	0.00	0.00
PS Not Subject Mandatory Redemption	0.00	0.00	0.00

Kentucky Power Corp Consol
Comparative Balance Sheet
May 31, 2013

Run Date: 06/11/2013 13:44

X_OPR_COS / KYP_CORP_C(	Rpt ID: GLR2200V Layout: GLR2200V / V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
	CUMULATIVE PREFERRED STOCK	**0.00**	**0.00**	**0.00**
	TRUST PREFERRED SECURITIES	**0.00**	**0.00**	**0.00**
	Long-Term Debt Less Amt Due 1 Yr	**549,291,418.75**	**549,221,950.00**	**69,468.75**
	CAPITALIZATION	**1,037,967,176.70**	**1,028,831,985.05**	**9,135,191.65**
	Obligations Under Capital Lease-NonCurrent	1,871,938.13	1,674,300.89	197,637.24
	Accumulated Provision Rate Relief	704,292.00	1,635,430.00	(931,138.00)
	Accumlated Provision - Miscellanous	36,319,431.89	34,033,794.12	2,285,637.77
	Other NonCurrent Liabilities	**38,895,662.02**	**37,343,525.01**	**1,552,137.01**
	Preferred Stock Due Within 1 Year	0.00	0.00	0.00
	Long-Term Debt Due Within 1 Year	0.00	0.00	0.00
	Accumulated Provision Due Within 1 Year	0.00	0.00	0.00
	Short-Term Debt	0.00	0.00	0.00
	Advances from Affiliates	0.00	13,358,855.63	(13,358,855.63)
	A/P General	19,369,335.96	30,336,776.64	(10,967,440.68)
	A/P Associated Companies	30,490,096.28	41,052,680.18	(10,562,583.90)
	Customer Deposits	24,672,951.28	23,484,964.81	1,187,986.47
	Taxes Accrued	6,346,513.87	6,548,714.64	(202,200.77)
	Interest Accrued	10,930,743.39	7,166,695.02	3,764,048.37
	Dividends Accrued	0.00	0.00	0.00
	Obligation Under Capital Leases	1,270,367.79	1,403,875.95	(133,508.16)
	Energy Contracts Current	2,156,659.53	3,320,068.02	(1,163,408.49)
	Other Current and Accrued Liabilities	15,029,997.07	17,797,808.10	(2,767,811.03)
	Current Liabilities	**110,266,665.17**	**144,470,438.99**	**(34,203,773.83)**
	Deferred Income Taxes	**391,124,343.97**	**385,153,166.17**	**5,971,177.80**
	Deferred Investment Tax Credits	**259,921.72**	**355,758.82**	**(95,837.10)**
	Regulatory Liabilities	**5,699,797.46**	**13,831,965.72**	**(8,132,168.26)**
2440002	LT Unreal Losses - Non Affil	2,521,991.89	4,200,196.07	(1,678,204.18)
2440022	L/T Liability MTM Collateral	(92,936.00)	(582,545.00)	489,609.00
2450011	L/T Liability-Commodity Hedges	7,563.00	82,731.00	(75,168.00)
	Long-Term Energy Trading Contracts	2,436,618.89	3,700,382.07	(1,263,763.18)
2520000	Customer Adv for Construction	59,401.36	63,177.74	(3,776.38)
	Customer Advances for Construction	59,401.36	63,177.74	(3,776.38)
	Deferred Gains on Sale/Leaseback	0.00	0.00	0.00
	Deferred Gains on Dispostion of Utility Plant	0.00	0.00	0.00
2530000	Other Deferred Credits	0.00	0.00	0.00
2530022	Customer Advance Receipts	1,564,239.53	2,634,497.53	(1,070,258.00)
2530050	Deferred Rev -Pole Attachments	97,588.73	78,940.35	18,648.38
2530067	IPP - System Upgrade Credits	263,810.52	260,279.72	3,530.80
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	160,250.00	162,614.00	(2,364.00)
2530112	Other Deferred Credits-Curr	987,972.74	1,113,326.72	(125,353.98)
2530114	Federl Mitigation Deferal(NSR)	754,941.55	754,941.55	0.00

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Kentucky Power Corp Consol
Comparative Balance Sheet
May 31, 2013

Run Date: 06/11/2013 13:44

X_OPR_COS / KYP_CORP_C(	Rpt ID: GLR2200V Layout: GLR2200V / V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
2530137	Fbr Opt Lns-Sold-Defd Rev	111,081.17	116,729.42	(5,648.25)
	Other Deferred Credits	3,939,884.24	5,121,329.29	(1,181,445.05)
	Deferred Credits	**6,435,904.49**	**8,884,889.10**	(2,448,984.61)
	DEFERRED CREDITS & REGULATED LIABILITIES	**403,519,967.64**	**408,225,779.81**	(4,705,812.17)
	CAPITAL & LIABILITIES	**1,590,649,471.53**	**1,618,871,728.87**	(28,222,257.34)

Statement of Retained Earnings

	BALANCE AT BEGINNING OF YEAR	**190,818,915.56**	**171,840,462.36**	18,978,453.21
	Net Income (Loss)	21,344,178.76	50,978,453.21	(29,634,274.45)
	Deductions:			
	Dividend Declared On Common Stock	(12,500,000.00)	-32,000,000	19,500,000.00
	Dividend Declared On Preferred Stock	0.00	0	0.00
	Adjustment in Retained Earnings	0.00	0.00	(0.00)
	Total Deductions	(12,500,000.00)	(32,000,000.00)	19,500,000.00
	BALANCE AT END OF PERIOD (A)	**199,663,094.32**	**190,818,915.56**	8,844,178.76

(A) Represents The Following Balances At End Of Period

215.0	Appropriated Retained Earnings	0.00	0.00	0.00
215.1	Appr Retnd Erngs - Amrt Rsv, Fed	0.00	0.00	0.00
	Total Appropriated Retained Earnings	0.00	0.00	0.00
2160000-1	Unapprp Retained Earnings Unrestr	190,818,915.56	171,840,462.36	18,978,453.21
2160002+	Unapprp Retained Earnings Restr	0.00	0.00	0.00
210.0	Gain on Reacquired Pref Stock	0.00	0.00	0.00
	Net Income Transferred	8,844,178.76	18,978,453.21	(10,134,274.45)
	Total Unappropriated Retained Earnings	199,663,094.32	190,818,915.56	8,844,178.76
216.1	Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
418.1	Equity Earnings of Subsidiary Co	0.00	0.00	0.00
	Total Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
	Total Other Retained Earnings Accounts	0.00	0.00	(0.00)
	TOTAL RETAINED EARNINGS	**199,663,094.32**	**190,818,915.56**	8,844,178.76

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - May, 2014

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	9,742,248.89	(2,266,690.57)	(9.12)	0.00	1,486,159,801.08
	TOTAL PRODUCTION	1,478,684,251.88	9,742,248.89	(2,266,690.57)	(9.12)	0.00	1,486,159,801.08
101/106	TRANSMISSION	503,165,571.80	4,914,646.92	(64,785.75)	0.00	0.00	508,015,432.97
101/106	DISTRIBUTION	733,776,590.81	14,038,971.85	(3,050,446.99)	0.00	0.00	744,765,115.67
	TOTAL (ACCOUNTS 101 & 106)	2,715,626,414.49	28,695,867.66	(5,381,923.31)	(9.12)	0.00	2,738,940,349.72
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	527,720.03	0.00	6,806,869.20
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	2,721,905,563.66	28,695,867.66	(5,381,923.31)	527,710.91	0.00	2,745,747,218.92
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	CONSTRUCTION WORK IN PROGRESS:						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		50,279,863.93				
107000X	TRANSFERS		(28,695,867.66)				
107000X	END. BAL.		21,583,996.27				150,183,144.46
	TOTAL ELECTRIC UTILITY PLANT	2,857,910,670.58	50,279,863.93	(5,381,923.31)	527,710.91	0.00	2,903,336,322.11
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	5,529,435.74	0.00	0.00	(0.03)	0.00	5,529,435.71

Prepared by: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

Final 06/11/2014

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - May, 2014

GLR7410V 06/11/14 08:0

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	23,129,358.96	(2,266,690.57)	(374,390.24)	0.00	619,992,405.04
1080001/11	TRANSMISSION	161,537,795.16	3,607,610.89	(64,785.75)	(206,372.90)	0.00	164,874,247.40
1080001/11	DISTRIBUTION	192,744,660.64	10,539,410.08	(3,050,446.99)	(628,612.09)	0.00	199,605,011.64
1080013	PRODUCTION	(3,620,015.26)	0.00	0.00	0.00	(218,757.52)	(3,838,772.78)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698.85)	0.00	0.00	0.00	(3,820.98)	(30,519.83)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(2,751,924.38)	1,209,375.23	(9,862,801.67)
	TOTAL (108X accounts)	**941,819,616.07**	**37,276,379.93**	**(5,381,923.31)**	**(3,961,299.61)**	**986,796.73**	**970,739,569.81**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	556,922.31	0.00	0.00	84,795.27	11,071,068.45
1110001	TRANSMISSION	1,607,792.68	241,147.67	0.00	0.00	0.00	1,848,940.35
1110001	DISTRIBUTION	7,182,584.75	633,830.76	0.00	0.00	0.00	7,816,415.51
	TOTAL (111X accounts)	**19,219,728.30**	**1,431,900.74**	**0.00**	**0.00**	**84,795.27**	**20,736,424.31**
1011006	CAPITAL LEASES	1,869,467.09	0.00	0.00	0.00	57,705.89	1,927,172.98
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**962,908,811.46**	**38,708,280.67**	**(5,381,923.31)**	**(3,961,299.61)**	**1,129,297.89**	**993,403,167.10**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	214,855.75	2,779.05	0.00	0.00	0.00	217,734.80
1240027	Other Property - RWIP	(3,400.00)	0.00	0.00	0.00	0.00	(3,400.00)
	TOTAL NONUTILITY PLANT	**211,455.75**	**2,779.05**	**0.00**	**0.00**	**0.00**	**214,334.80**

Prepared by. PSnVision Report GLR7410V
Reviewer: Cindy Buckbee -- Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

AEP
AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

July 21, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed June 2014 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-9	Income Statement
1-3	Details of Operating Revenues
4-7	Operating Expenses – Functional Expenses
8-9	Detail Statement of Taxes

Balance Sheet:

10	Balance Sheet – Assets & Other Debits
10-12	Balance Sheet – Liabilities & Other Credits
11-12	Deferred Credits
12	Statement of Retained Earnings

Utility Property:

13-14	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Brian J. Frantz
Manager –Regulated Accounting

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jun 2014
07/08/2014 18 15

Layout: GLS8016
099 V2014-06-30 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Jun 2014	Kentucky Power Company - Distribution 110 Actual YTD Jun 2014	Kentucky Power Company - Generation 117 Actual YTD Jun 2014	Kentucky Power Company - Transmission 180 Actual YTD Jun 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	65,869,484	66,077,904	(208,420)	0
4400002		Residential Sales-W/O Space Ht	27,709,096	27,867,963	(158,867)	0
4400005		Residential Fuel Rev	40,376,332	40,376,332	0	0
	A	**Revenue - Residential Sales**	**133,954,912**	**134,322,199**	**(367,287)**	-
4420001		Commercial Sales	38,840,770	38,814,513	26,257	0
4420006		Sales to Pub Auth - Schools	7,261,156	7,174,244	86,912	0
4420007		Sales to Pub Auth - Ex Schools	7,262,597	7,242,798	19,799	0
4420013		Commercial Fuel Rev	22,090,529	22,090,529	0	0
	A	**Revenue - Commercial Sales**	**75,455,052**	**75,322,085**	**132,967**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	31,936,026	31,799,317	136,708	0
4420004		Ind Sales-NonAffil(Incl Mines)	15,456,063	15,318,905	137,158	0
4420016		Industrial Fuel Rev	46,153,913	46,153,913	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**93,546,002**	**93,272,135**	**273,867**	-
		Revenue - Industrial Sales	**93,546,002**	**93,272,135**	**273,867**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	738,459	731,215	7,244	0
4440002		Public St & Hwy Light Fuel Rev	161,855	161,855	0	0
	A	**Revenue - Other Retail Sales**	**900,314**	**893,070**	**7,244**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**303,856,280**	**303,809,489**	**46,791**	-
4560043		Oth Elec Rv-Trn-Aff Trnf Price	0	0	0	17,712,122
4561033		PJM NITS Revenue - Affiliated	5,927,747	0	0	18,100,872
4561034		PJM TO Adm. Serv Rev - Aff	0	0	0	283,818
4561035		PJM Affiliated Trans NITS Cost	(5,910,528)	0	(18,083,653)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(283,818)	0
4561059		Affil PJM Trans Enhancmnt Rev	54,482	0	0	162,702
4561060		Affil PJM Trans Enhancmnt Cost	(54,328)	0	(162,548)	0
4561062		PROVISION RTO Cost - Affi	(1,664,598)	0	(1,664,598)	0
4561063		PROVISION RTO Rev Affiliated	2,722,731	0	0	2,722,731
	B	**Revenue - Transmission-Affiliated**	**1,075,506**	-	**(20,194,617)**	**38,982,245**
4470150		Transm. Rev. Dedic. Whlsl/Muni	(11,695)	0	(376,573)	364,878
4470206		PJM Trans loss credits-OSS	1,363,306	0	1,363,306	0
4470207		PJM transm loss charges - LSE	(11,253,792)	0	(11,253,792)	0
4470208		PJM Transm loss credits-LSE	1,743,143	0	1,743,143	0
4470209		PJM transm loss charges-OSS	(10,698,353)	0	(10,698,353)	0
4561002		RTO Formation Cost Recovery	1,343	0	(71,268)	72,611
4561003		PJM Expansion Cost Recov	40,124	0	(44,341)	84,465
4561005		PJM Point to Point Trans Svc	356,403	0	356,403	0
4561006		PJM Trans Owner Admin Rev	134,335	0	0	134,335
4561007		PJM Network Integ Trans Svc	7,252,867	0	0	7,252,867
4561019		Oth Elec Rev Trans Non Affil	30,671	0	0	30,671
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	3,748	0	0	3,748
4561029		PJM NITS Revenue Whsl Cus-NAff	1,346,911	0	0	1,346,911
4561030		PJM TO Serv Rev Whls Cus-NAff	20,261	0	0	20,261
4561058		NonAffil PJM Trans Enhncmt Rev	167,667	0	0	167,667
4561061		NAff PJM RTEP Rev for Whsl-FR	12,107	0	0	12,107
4561064		PROVISION RTO Rev WhslCus-NAf	204,403	0	0	204,403
4561065		PROVISION RTO Rev - NonAff	1,108,591	0	0	1,108,591
	A	**Revenue - Transmission-NonAffiliated**	**(8,177,959)**	-	**(18,981,474)**	**10,803,515**
		Revenue - Transmission	**(7,102,453)**	-	**(39,176,091)**	**49,785,760**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	262	0	262	0
4470128		Sales for Res-Aff. Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,479,520**	-	**5,479,520**	-
4470002		Sales for Resale - NonAssoc	2,725	0	2,725	0
4470006		Sales for Resale-Bookout Sales	9,092,354	0	9,092,354	0
4470010		Sales for Resale-Bookout Purch	(9,951,305)	0	(9,951,305)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,437,695	0	1,437,695	0
4470028		Sale/Resale - NA - Fuel Rev	151,564	0	151,564	0
4470033		Whsal/Muni/Pub Auth Base Rev	2,531,680	0	2,531,680	0
4470066		PWR Trding Trans Exp-NonAssoc	(64)	0	(64)	0
4470081		Financial Spark Gas - Realized	23,040	0	23,040	0
4470082		Financial Electric Realized	2,366,550	0	2,366,550	0
4470089		PJM Energy Sales Margin	88,507,869	0	88,507,869	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jun 2014
07/08/2014 18:15
Layout: GLS8016
098 V2014-06-30 Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Jun 2014	Kentucky Power Company - Distribution 110 Actual YTD Jun 2014	Kentucky Power Company - Generation 117 Actual YTD Jun 2014	Kentucky Power Company - Transmission 180 Actual YTD Jun 2014
4470093		PJM Implicit Congestion-LSE	(17,093,078)	0	(17,093,078)	0
4470098		PJM Oper Reserve Rev-OSS	(2,770,504)	0	(2,770,504)	0
4470099		Capacity Cr. Net Sales	261,146	0	261,146	0
4470100		PJM FTR Revenue-OSS	622,050	0	622,050	0
4470101		PJM FTR Revenue-LSE	7,685,089	0	7,685,089	0
4470103		PJM Energy Sales Cost	94,719,927	0	94,719,927	0
4470106		PJM PtZPt Trans Purch-NonAff	(27)	0	(27)	0
4470107		PJM NITS Purch-NonAff	19,229	0	19,229	0
4470109		PJM FTR Revenue-Spec	(52,763)	0	(52,763)	0
4470110		PJM TO Admin. Exp.-NonAff	35,073	0	35,073	0
4470112		Non-Trading Bookout Sales-OSS	4,943	0	4,943	0
4470115		PJM Meter Corrections-OSS	(10,230)	0	(10,230)	0
4470116		PJM Meter Corrections-LSE	40,545	0	40,545	0
4470124		PJM Incremental Spot-OSS	1	0	1	0
4470126		PJM Incremental Imp Cong-OSS	(24,345,469)	0	(24,345,469)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	(283,399)	0	(283,399)	0
4470144		Realiz Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim. Margin Reclass	(175)	0	(175)	0
4470166		Interest Rate Swaps-Power	(9,493)	0	(9,493)	0
4470170		Non-ECR Auction Sales-OSS	1,405,218	0	1,405,218	0
4470174		PJM Whlse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	206,124	0	206,124	0
4470176		OSS Sharing Reclass-Reduction	(206,124)	0	(206,124)	0
4470180		Trading intra-book Reclass	(119,770)	0	(119,770)	0
4470181		Auction intra-book Reclass	119,770	0	119,770	0
4470202		PJM OpRes-LSE-Credit	571,890	0	571,890	0
4470203		PJM OpRes-LSE-Charge	(4,593,671)	0	(4,593,671)	0
4470204		PJM Spinning-Credit	(0)	0	(0)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,200	0	28,200	0
4470220		PJM Regulation - OSS	105,057	0	105,057	0
4470221		PJM Spinning Reserve - OSS	8,646	0	8,646	0
4470222		PJM Reactive - OSS	312,310	0	312,310	0
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	(10,423)	0	(10,423)	0
5550080		PJM Hourly Net Purch - FERC	(21,322,334)	0	(21,322,334)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**129,491,479**	-	**129,491,479**	-
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**134,970,999**	-	**134,970,999**	-
4470074		Sale for Resale-Aff-Trnf Price	0	0	226,094,993	0
4540001		Rent From Elect Property - Af	130,374	388,691	0	0
4560001		Oth Elect Rev - Affiliated	4,906	0	4,906	0
	B	**Revenue - Other Ele-Affiliated**	**135,280**	**388,691**	**226,099,899**	-
4500000		Forfeited Discounts	2,038,742	2,038,742	0	0
4510001		Misc Service Rev - Nonaffil	184,991	178,213	0	6,778
4540002		Rent From Elect Property-NAC	60,864	1,200	56,989	2,675
4540005		Rent from Elec Prop-Pole Attch	2,233,400	2,233,400	0	0
4560007		Oth Elect Rev - DSM Program	2,986,757	2,986,757	0	0
		Revenue - Other Ele-NonAffiliated	**7,504,754**	**7,438,312**	**56,989**	**9,453**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	383	0	383	0
4118004		Comp. Allow. Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,916**	-	**8,916**	-
	A	**Revenue - Other Ele-NonAffiliated**	**7,513,670**	**7,438,312**	**65,905**	**9,453**
		Revenue - Other Opr Electric	**7,648,950**	**7,827,003**	**226,165,803**	**9,453**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	16,600	16,000	600	0
4180003		Non-Opratng Rntal Inc-Maint	(16)	0	(16)	0
4180005		Non-Opratng Rntal Inc-Depr	(3,335)	0	0	(3,335)
	D	**Non-Operating Rental Income - NonAffiliated**	**13,250**	**16,000**	**584**	**(3,335)**
		Non-Operating Rental Income	**13,250**	**16,000**	**584**	**(3,335)**

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	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	1,175	354	500	321
4210007		Misc Non-Op Inc - NonAsc - Oth	72,457	394	72,063	0
	D	**Non-Operating Misc Income - NonAffiliated**	**73,632**	**748**	**72,563**	**321**
		Non-Operating Misc Income	**73,632**	**748**	**72,563**	**321**
4540004		Rent From Elect Prop-ABD-Nonaf	46,300	46,300	0	0
4560015		Other Electric Revenues - ABD	134,871	120,644	0	14,227
	D	**Associated Business Development Income**	**181,171**	**166,944**	-	**14,227**
		Revenue - Other Opr - Other	**268,053**	**183,692**	**73,148**	**11,213**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***268,053***	***183,692***	***73,148***	***11,213***
		Revenue - Other Operating	**7,917,002**	**8,010,696**	**226,238,951**	**20,666**
	A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	-	-	-	-
4210031		Pwr Sales Outside Svc Territry	51,759	0	51,759	0
4210032		Pwr Purch Outside Svc Territry	(555)	0	(555)	0
	A	**Revenue - Power Sales**	**51,204**	-	**51,204**	-
		TOTAL OPERATING REVENUES	**439,693,032**	**311,820,184**	**322,131,853**	**49,806,426**
=(A)		*Memo: G/T/D Revenue*	*432,734,674*	*311,247,801*	*110,673,904*	*10,812,968*
=(B)		*Memo: Other Affiliated Revenue*	*6,690,305*	*388,691*	*211,384,802*	*38,982,245*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Non*	*268,053*	*183,692*	*73,148*	*11,213*
		Memo: Total Operating Revenues	*439,693,032*	*311,820,184*	*322,131,853*	*49,806,426*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***6,690,305***	***388,691***	***211,384,802***	***38,982,245***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***433,002,727***	***311,431,494***	***110,747,052***	***10,824,181***
		Memo: Total Operating Revenues	***439,693,032***	***311,820,184***	***322,131,853***	***49,806,426***
		FUEL EXPENSES				
5010000		Fuel	313,401	0	313,401	0
5010001		Fuel Consumed	145,528,554	0	145,528,554	0
5010003		Fuel - Procure Unload & Handle	6,645,188	0	6,645,188	0
5010013		Fuel Survey Activity	(734,602)	0	(734,602)	0
5010019		Fuel Oil Consumed	3,447,281	0	3,447,281	0
5010027		Gypsum handling/disposal costs	206,244	0	206,244	0
5010028		Gypsum Sales Proceeds	(388,311)	0	(388,311)	0
		Fuel Expense Total	**155,017,755**	-	**155,017,755**	-
5010005		Fuel - Deferred	(13,025,208)	0	(13,025,208)	0
		Deferred Fuel Expense	**(13,025,208)**	-	**(13,025,208)**	-
		Over Under Fuel Expense				
		Fuel for Electric Generation	**141,992,547**	-	**141,992,547**	-
5010029		Gypsum handling/displ-Affiliat	87,186	0	87,186	0
		Fuel from Affiliates for Electric Generation	**87,186**	-	**87,186**	-
5090000		Allow Consum Title IV SO2	4,816,168	0	4,816,168	0
5090001		Allowance Consumption - NOx	12,837	0	12,837	0
5090005		An NOx Cons Exp	70,971	0	70,971	0
		Allowances - Consumption	**4,899,975**	-	**4,899,975**	-
5020002		Urea Expense	2,735,701	0	2,735,701	0
5020003		Trona Expense	182,136	0	182,136	0
5020004		Limestone Expense	2,016,659	0	2,016,659	0
5020005		Polymer expense	44,984	0	44,984	0
5020007		Lime Hydrate Expense	8,396	0	8,396	0
		Emissions Control - Chemicals	**4,987,877**	-	**4,987,877**	-
		Total Fuel for Electric Generation	**151,967,586**	-	**151,967,586**	-
		Memo: NonAff Fuel/Allow/Emissions	***151,880,399***	-	***151,880,399***	-
5550004		Purchased Power-Pool Capacity	181,949	0	181,949	0
5550005		Purchased Power - Pool Energy	676,093	0	676,093	0
5550027		Purch Pwr-Non-Fuel Portion-Aff	24,673,268	0	24,673,268	0
5550029		Purch Power Assoc Trnsh Price	0	226,094,993	0	0
5550046		Purch Power-Fuel Portion-Affil	33,445,957	0	33,445,957	0
5550101		Purch Power-Pool Non-Fuel -Aff	168,508	0	168,508	0
5550102		Pur Power Pool NonFuel-OSS Aff	214,985	0	214,985	0
		Purchased Electricity from AEP - Affiliates	**59,360,760**	**226,094,993**	**59,360,760**	-
5550000		Purchased Power	34	0	33	1
5550001		Purch Pwr-NonTrading-Nonassoc	488,131	0	488,131	0
5550032		Gas-Conversion-Mone Plant	3,282	0	3,282	0
5550039		PJM Inadvertent Mtr Res-OSS	(65,551)	0	(65,551)	0

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		Kentucky Power Int Consol GLS8016 Actual YTD Jun 2014	Kentucky Power Company - Distribution 110 Actual YTD Jun 2014	Kentucky Power Company - Generation 117 Actual YTD Jun 2014	Kentucky Power Company - Transmission 180 Actual YTD Jun 2014
5550040	PJM Inadvertent Mtr Res-LSE	(32,790)	0	(32,790)	0
5550041	PJM Ancillary Serv -Sync	5,464	0	5,464	0
5550074	PJM Reactive-Charge	(11,793)	0	(11,793)	0
5550076	PJM Black Start-Charge	669,122	0	669,122	0
5550077	PJM Black Start-Credit	(7)	0	(7)	0
5550078	PJM Regulation-Charge	1,470,976	0	1,470,976	0
5550079	PJM Regulation-Credit	(339,293)	0	(339,293)	0
5550083	PJM Spinning Reserve-Charge	1,310,965	0	1,310,965	0
5550084	PJM Spinning Reserve-Credit	(317,476)	0	(317,476)	0
5550090	PJM 30m Suppl Rserv Charge LSE	386,553	0	386,553	0
5550099	PJM Purchases-non-ECR-Auction	1,476,048	0	1,476,048	0
5550100	Capacity Purchases-Auction	42,383	0	42,383	0
5550107	Capacity purchases - Trading	83,593	0	83,593	0
	Purchased Electricity for Resale - NonAffiliated	**5,169,639**	**-**	**5,169,638**	**1**
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	**64,530,399**	**226,094,993**	**64,530,398**	**1**
	GROSS MARGIN	**223,196,047**	**86,726,192**	**105,633,870**	**49,806,425**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	1,858,484	0	1,858,484	0
5000001	Oper Super & Eng-RATA-Affil	40,462	0	40,462	0
5020000	Steam Expenses	1,248,713	0	1,248,713	0
5050000	Electric Expenses	293,210	0	293,210	0
5060000	Misc Steam Power Expenses	3,964,688	0	3,964,688	0
5060002	Misc Steam Power Exp-Assoc	29,660	0	29,660	0
5060003	Removal Cost Expense - Steam	(77,750)	0	(77,750)	0
5060004	NSR Settlement Expense	(1,427)	0	(1,427)	0
5060025	Misc Stm Pwr Exp Environmental	(11)	0	(11)	0
	Steam Generation Op Exp	**7,356,029**	**-**	**7,356,029**	**-**
	Nuclear Generation Op Exp	-	-	-	-
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	264,272	(20)	264,243	49
5570000	Other Expenses	876,212	173	875,994	45
5570007	Other Pwr Exp - Wholesale RECs	11,866	11,866	0	0
5757000	PJM Admin-MAM&SC- OSS	285,517	0	285,517	0
5757001	PJM Admin-MAM&SC- Internal	385,509	0	385,509	(0)
	Other Generation Op Exp	**1,823,376**	**12,019**	**1,811,263**	**94**
5600000	Oper Supervision & Engineering	527,352	1,413	2,585	523,354
5611000	Load Dispatch - Reliability	4,409	0	0	4,409
5612000	Load Dispatch-Mntr&Op TransSys	440,712	45	75	440,591
5614000	PJM Admin-SSC&DS-OSS	254,222	0	254,222	0
5614001	PJM Admin-SSC&DS-Internal	345,544	0	345,544	0
5614007	RTO Admin Default LSE	3,874	0	3,539	335
5614008	PJM Admin Defaults OSS	2,417	0	2,417	0
5615000	Reliability,Plng&Stds Develop	52,268	4,145	6,444	41,678
5618000	PJM Admin-RP&SDS-OSS	65,693	0	65,693	0
5618001	PJM Admin-RP&SDS- Internal	87,713	0	87,713	0
5620001	Station Expenses - Nonassoc	159,635	0	0	159,635
5630000	Overhead Line Expenses	90,669	0	0	90,669
5650002	Transmssn Elec by Others-NAC	100,633	0	100,633	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	17,712,122	0	0
5650012	PJM Trans Enhancement Charge	1,978,492	0	1,978,492	0
5650015	PJM TO Serv Exp - Aff	17,989	0	17,989	0
5650016	PJM NITS Expense - Affiliated	1,916,833	0	1,916,833	0
5650019	Affil PJM Trans Enhncement Exp	96,851	0	96,851	0
5650020	PROVISION RTO Aff Expense	1,273,709	0	1,273,709	0
5660000	Misc Transmission Expenses	663,779	5,273	7,572	650,934
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	258,317
5757002	SPP Admin-MAM&SC	0	0	0	0
	Transmission Op Exp	**8,083,045**	**17,723,000**	**6,160,312**	**2,170,172**
5800000	Oper Supervision & Engineering	396,950	391,104	1,739	4,108
5810000	Load Dispatching	1,798	1,524	0	274
5820000	Station Expenses	112,053	110,315	0	1,738
5830000	Overhead Line Expenses	436,740	436,875	(135)	(0)
5840000	Underground Line Expenses	49,388	49,216	126	46
5841000	Oper of Energy Storage Equip	0	0	0	0

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5850000	Street Lighting & Signal Sys E	70,824	70,824	0	0
5860000	Meter Expenses	407,861	406,472	998	391
5870000	Customer Installations Exp	78,386	78,386	0	0
5880000	Miscellaneous Distribution Exp	1,886,472	1,867,954	4,467	14,050
5890001	Rents - Nonassociated	864,525	864,525	0	0
5890002	Rents - Associated	34,398	34,398	0	0
	Distribution Op Exp	**4,339,396**	**4,311,594**	**7,194**	**20,607**
9010000	Supervision - Customer Accts	146,801	146,727	54	20
9020000	Meter Reading Expenses	116	(170)	208	78
9020001	Customer Card Reading	325	97	167	61
9020002	Meter Reading - Regular	216,146	216,146	0	0
9020003	Meter Reading - Large Power	27,486	27,486	0	0
9020004	Read-In & Read-Out Meters	29,787	29,787	0	0
9030000	Cust Records & Collection Exp	183,848	180,230	132	3,485
9030001	Customer Orders & Inquiries	1,256,073	1,255,681	290	102
9030002	Manual Billing	20,651	19,913	5	734
9030003	Postage - Customer Bills	389,364	389,364	0	0
9030004	Cashiering	69,002	68,841	75	86
9030005	Collection Agents Fees & Exp	32,444	32,444	0	0
9030006	Credit & Oth Collection Activi	370,096	370,048	36	12
9030007	Collectors	290,109	290,109	0	0
9030009	Data Processing	82,022	82,010	9	3
9040007	Uncoll Accts - Misc Receivable	(55,924)	(60,648)	4,725	0
9050000	Misc Customer Accounts Exp	14,140	14,140	0	0
9070000	Supervision - Customer Service	81,097	81,097	(0)	0
9070001	Supervision - DSM	(11)	(4)	(4)	(3)
9080000	Customer Assistance Expenses	238,570	238,575	(3)	(2)
9080001	DSM-Customer Advisory Grp	862	862	0	0
9080009	Cust Assistance Expense - DSM	2,473,397	2,472,608	569	220
9090000	Information & Instruct Advrtis	52,867	16,044	26,806	10,017
9100000	Misc Cust Svc&Informational Ex	17,954	7,441	7,849	2,664
	Customer Service and Information Op Exp	**5,937,222**	**5,878,827**	**40,918**	**17,477**
9120000	Demonstrating & Selling Exp	11,547	11,547	0	0
9120003	Demo & Selling Exp - Area Dev	(321)	(321)	0	0
	Sales Expenses	**11,225**	**11,225**	**-**	**-**
	Memo: Insurance (9240 9250)	**557,695**	**298,210**	**167,342**	**92,143**
9200000	Administrative & Gen Salaries	4,808,393	2,132,411	1,987,947	688,036
9210001	Off Supl & Exp - Nonassociated	282,092	160,768	98,854	22,470
9210003	Office Supplies & Exp - Trnsf	6	6	0	0
9220000	Administrative Exp Trnsf - Cr	(265,409)	(265,409)	0	0
9220001	Admin Exp Trnsf to Cnstrction	(210,925)	(210,925)	0	0
9220004	Admin Exp Trnsf to ABD	(1,627)	(623)	0	(1,004)
9230001	Outside Svcs Empl - Nonassoc	639,516	280,420	267,169	91,928
9230002	Outside Svcs Empl - Assoc	(0)	0	(0)	0
9230003	AEPSC Billed to Client Co	(237,896)	(67,742)	(107,320)	(62,835)
9240000	Property Insurance	232,412	82,609	53,481	96,323
9250000	Injuries and Damages	572,291	409,019	139,646	23,626
9250001	Safety Dinners and Awards	3,120	1,399	1,372	348
9250002	Emp Accident Prvntion-Adm Exp	5,087	3,234	1,303	550
9250004	Injuries to Employees	1,075	0	1,075	0
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	(203,154)	(96,688)	(88,653)	(17,812)
9250007	Prsnal Injries&Prop Dmage-Pub	65,581	89	65,480	12
9250010	Frg Ben Loading - Workers Comp	(118,717)	(101,452)	(6,361)	(10,904)
9260000	Employee Pensions & Benefits	2,360	2,360	0	0
9260001	Edit & Print Empl Pub-Salaries	11,662	4,200	4,831	2,631
9260002	Pension & Group Ins Admin	22,622	11,411	10,044	1,167
9260003	Pension Plan	2,505,094	1,146,807	1,221,485	136,803
9260004	Group Life Insurance Premiums	77,072	31,177	40,858	5,036
9260005	Group Medical Ins Premiums	2,534,655	1,267,958	1,069,224	197,473
9260006	Physical Examinations	1	0	0	1
9260007	Group L-T Disability Ins Prem	8,931	6,327	2,209	394
9260009	Group Dental Insurance Prem	142,978	73,130	60,397	9,450
9260010	Training Administration Exp	278	115	120	43
9260012	Employee Activities	1,502	549	436	517
9260014	Educational Assistance Pmts	900	900	0	0
9260021	Postretirement Benefits - OPEB	(1,831,549)	(872,322)	(837,914)	(121,313)
9260027	Savings Plan Contributions	1,117,583	479,036	587,039	51,508
9260036	Deferred Compensation	4,325	4,325	0	0

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9260037	Supplemental Pension	120	120	0	0
9260040	SFAS 112 Postemployment Benef	428,525	0	428,525	0
9260050	Frg Ben Loading - Pension	(755,433)	(527,471)	(178,952)	(49,011)
9260051	Frg Ben Loading - Grp Ins	(894,282)	(629,374)	(189,275)	(75,634)
9260052	Frg Ben Loading - Savings	(360,697)	(221,245)	(109,970)	(29,482)
9260053	Frg Ben Loading - OPEB	202,187	161,014	20,446	20,727
9260055	IntercoFringeOffset- Don't Use	(891,158)	(196,825)	(613,027)	(81,306)
9260057	Postret Ben Medicare Subsidy	308,836	124,595	172,420	11,820
9260058	Frg Ben Loading - Accrual	(16,106)	9,391	(23,992)	(1,505)
9260060	Amort-Post Retirement Benefit	108,310	64,791	35,603	7,916
9270000	Franchise Requirements	70,975	70,975	0	0
9280000	Regulatory Commission Exp	24,917	8,918	10,270	5,728
9280001	Regulatory Commission Exp-Adm	2	1	1	1
9280002	Regulatory Commission Exp-Case	76,747	15,728	50,976	10,043
9301000	General Advertising Expenses	848	298	362	187
9301001	Newspaper Advertising Space	8,843	3,188	3,672	1,983
9301002	Radio Station Advertising Time	4,430	1,603	1,832	996
9301010	Publicity	2,235	802	952	481
9301012	Public Opinion Surveys	15,608	15,605	0	3
9301015	Other Corporate Comm Exp	7,928	5,159	1,879	890
9302000	Misc General Expenses	122,671	66,651	31,369	24,650
9302003	Corporate & Fiscal Expenses	19,839	4,041	14,769	1,029
9302004	Research, Develop&Demonstr Exp	2,974	2,974	0	0
9302458	AEPSC Non Affiliated expenses	(0)	0	(0)	0
9310001	Rents - Real Property	48,312	48,312	0	0
9310002	Rents - Personal Property	126,692	63,954	37,010	5,728
	Administration & General	**8,833,581**	**3,596,296**	**4,267,590**	**969,695**
4111005	Accretion Expense	482,632	0	482,632	0
	Accretion	**482,632**	-	**482,632**	-
4116000	Gain From Disposition of Plant	(2,010)	(2,010)	0	0
	Loss/(Gain) on Utility Plant	**(2,010)**	**(2,010)**	-	-
9302006	Assoc Bus Dev - Materials Sold	31,087	31,087	0	0
9302007	Assoc Business Development Exp	65,427	46,499	5	18,923
	Associated Business Development Expenses	**96,514**	**77,586**	**5**	**18,923**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4010001	Operation Exp - Nonassociated	30	0	30	0
4265009	Factored Cust A/R Exp - Affil	466,527	466,527	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	929,892	929,892	0	0
	Opr Exp and Factored A/R	**1,396,449**	**1,396,419**	**30**	-
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	43,751	15,577	18,866	9,309
	Expense of Non-Utility Operation	**43,751**	**15,577**	**18,866**	**9,309**
4210009	Misc Non-Op Exp - NonAssoc	4,784	1,090	3,013	681
	Misc NonOp Expenses - NonAssoc	**4,784**	**1,090**	**3,013**	**681**
4261000	Donations	201,560	122,151	68,417	10,993
	Donation Contributions	**201,560**	**122,151**	**68,417**	**10,993**
4263001	Penalties	62,109	23,921	24,132	14,056
	Provision for Penalties	**62,109**	**23,921**	**24,132**	**14,056**
4264000	Civic & Political Activities	129,731	47,513	52,142	30,077
	Civic & Political Activities	**129,731**	**47,513**	**52,142**	**30,077**
4265002	Other Deductions - Nonassoc	107	33	55	20
4265033	Transition Costs	5,267	0	5,267	0
	Other Deductions	**5,374**	**33**	**5,322**	**20**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**1,843,759**	**1,606,704**	**171,920**	**65,135**
	Operational Expenses	**38,804,768**	**33,216,240**	**20,297,863**	**3,262,104**
5100000	Maint Supv & Engineering	1,891,516	0	1,891,516	0
5110000	Maintenance of Structures	947,909	0	947,909	0
5120000	Maintenance of Boiler Plant	9,015,646	0	9,015,646	0
5130000	Maintenance of Electric Plant	1,485,221	0	1,485,221	0
5140000	Maintenance of Misc Steam Plt	797,605	0	797,605	0
	Steam Generation Maintenance	**14,137,896**	-	**14,137,896**	-
	Nuclear Generation Maintenance	-	-	-	-
	Hydro Generation Maintenance	-	-	-	-
	Other Generation Maintenance	-	-	-	-

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jun 2014
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Layout: GLS8016

098 V2014-06-30	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Jun 2014	Kentucky Power Company - Distribution 110 Actual YTD Jun 2014	Kentucky Power Company - Generation 117 Actual YTD Jun 2014	Kentucky Power Company - Transmission 180 Actual YTD Jun 2014
5680000	Maint Supv & Engineering	43,144	18	8	43,117
5690000	Maintenance of Structures	3,439	0	0	3,439
5691000	Maint of Computer Hardware	10,939	0	(1)	10,940
5692000	Maint of Computer Software	143,551	2,556	0	140,995
5693000	Maint of Communication Equip	7,828	0	0	7,828
5700000	Maint of Station Equipment	383,069	18,210	0	364,859
5710000	Maintenance of Overhead Lines	808,168	(1,786)	55	809,899
5720000	Maint of Underground Lines	15	0	0	15
5730000	Maint of Misc Trnsmssion Plt	137,063	0	0	137,063
	Transmission Maintenance	**1,537,215**	**18,999**	**62**	**1,518,153**
5900000	Maint Supv & Engineering	1,575	1,585	(1)	(9)
5910000	Maintenance of Structures	6,908	6,346	0	562
5920000	Maint of Station Equipment	328,420	326,824	21	1,574
5930000	Maintenance of Overhead Lines	16,747,320	16,744,208	2,583	529
5930001	Tree and Brush Control	172,873	172,873	0	0
5930008	Maint Ovh Lines Strm Exp-OvUnd	1,292	1,292	0	0
5930010	Storm Expense Amortization	2,349,222	2,349,222	0	0
5940000	Maint of Underground Lines	41,928	41,928	0	0
5950000	Maint of Lne Trnf Rglators&Dvi	32,369	32,369	0	0
5960000	Maint of Strt Lghtng & Sgnal S	31,462	31,462	0	0
5970000	Maintenance of Meters	39,303	37,570	0	1,733
5980000	Maint of Misc Distribution Plt	103,068	102,558	0	510
	Distribution Maintenance	**19,855,741**	**19,848,238**	**2,604**	**4,900**
9350000	Maintenance of General Plant	179	0	0	179
9350001	Maint of Sructures - Owned	141,965	139,911	(130)	2,183
9350002	Maint of Structures - Leased	25,774	24,109	1,078	586
9350003	Maint of Prprty Held Fture Use	451	(1)	454	(1)
9350006	Maint of Carrier Equipment	13	13	0	0
9350012	Maint of Data Equipment	346	0	346	0
9350013	Maint of Cmmncation Eq-Unall	363,908	336,462	27,446	0
9350015	Maint of Office Furniture & Eq	301,862	144,272	157,591	0
9350016	Maintenance of Video Equipment	120	120	0	0
9350019	Maint of Gen Plant-SCADA Equ	222	219	2	0
9350023	Site Communications Services	286	0	286	0
9350024	Maint of DA-AMI Comm Equip	59	59	0	0
	Administration & General Maintenance	**835,185**	**645,164**	**187,073**	**2,947**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**36,366,037**	**20,512,401**	**14,327,635**	**1,526,000**
	Total Operational and Maintenance Expenses	**75,170,805**	**53,727,641**	**34,625,499**	**4,788,104**
4040001	Amort. of Plant	1,729,912	765,721	672,473	291,717
4060001	Amort of Plt Acq Adj	19,308	0	0	19,308
	DDA Amortization	**1,749,220**	**765,721**	**672,473**	**311,025**
4073000	Regulatory Debits	144,543	0	0	144,543
	DDA Regulatory Debits	**144,543**	-	-	**144,543**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**1,893,763**	**765,721**	**672,473**	**455,569**
4030001	Depreciation Exp	44,418,056	12,658,478	27,428,385	4,331,194
	DDA Depreciation	**44,418,056**	**12,658,478**	**27,428,385**	**4,331,194**
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	243,039	0	243,039	0
	DDA Asset Retirement Obligation	**243,039**	-	**243,039**	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**44,661,094**	**12,658,478**	**27,671,423**	**4,331,194**
	Depreciation and Amortization	**46,554,857**	**13,424,199**	**28,343,896**	**4,786,762**
	Franchise Taxes	-	-	-	-
408100613	State Gross Receipts Tax	(5,942)	1	(5,943)	0
408100614	State Gross Receipts Tax	30,223	0	30,223	0
	Revenue-kWhr Taxes	**24,281**	**1**	**24,280**	-
4081002	FICA	2,048,796	863,349	1,089,086	96,361
4081003	Federal Unemployment Tax	18,231	7,919	9,340	972
4081007	State Unemployment Tax	58,158	19,900	35,859	2,399
4081033	Fringe Benefit Loading - FICA	(646,915)	(395,952)	(196,729)	(54,234)
4081034	Fringe Benefit Loading - FUT	(4,619)	(2,732)	(1,612)	(275)
4081035	Fringe Benefit Loading - SUT	(12,077)	(5,881)	(5,580)	(616)
	Payroll Taxes	**1,461,574**	**486,602**	**930,363**	**44,609**
408102014	State Business Occup Taxes	1,986,285	0	1,986,285	0
	Capacity Taxes	**1,986,285**	-	**1,986,285**	-

American Electric Power

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INCOME STATEMENT

Layout: GLS8016

098 V2014-06-30	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Jun 2014	Kentucky Power Company - Distribution 110 Actual YTD Jun 2014	Kentucky Power Company - Generation 117 Actual YTD Jun 2014	Kentucky Power Company - Transmission 180 Actual YTD Jun 2014
408100509	Real & Personal Property Taxes	3,975	3,907	0	69
408100510	Real Personal Property Taxes	131	131	0	0
408100512	Real Personal Property Taxes	1,587,617	112,328	1,447,806	27,484
408100513	Real Personal Property Taxes	5,115,620	2,996,622	451,058	1,667,940
408102910	Real-Pers Prop Tax-Cap Leases	12	12	0	0
408102913	Real-Pers Prop Tax-Cap Leases	1,038	790	68	180
408102914	Real-Pers Prop Tax-Cap Leases	10,746	8,112	624	2,010
408103613	Real Prop Tax-Cap Leases	(1,473)	(1,473)	0	0
408103614	Real Prop Tax-Cap Leases	12,750	12,750	0	0
408200513	Real Personal Property Taxes	28,302	4,836	0	23,466
	Property Taxes	**6,758,719**	**3,138,014**	**1,899,556**	**1,721,149**
408101813	St Publ Serv Comm Tax-Fees	473,122	473,122	0	0
	Regulatory Fees	**473,122**	**473,122**	**-**	**-**
408101414	Federal Excise Taxes	986	0	986	0
	Production Taxes	**986**	**-**	**986**	**-**
408101714	St Lic Rgstrtion Tax-Fees	200	200	0	0
408101900	State Sales and Use Taxes	(342,470)	(156,655)	(178,775)	(7,040)
408101912	State Sales and Use Taxes	218,039	89,065	119,078	9,896
408101913	State Sales and Use Taxes	1,295	1,295	0	0
408101914	State Sales and Use Taxes	8,515	8,515	0	0
408102214	Municipal License Fees	300	300	0	0
	Miscellaneous Taxes	**(114,121)**	**(57,279)**	**(59,697)**	**2,856**
	Other Non-Income Taxes	**(113,134)**	**(57,279)**	**(58,711)**	**2,856**
	Taxes Other Than Income Taxes	**10,590,846**	**4,040,459**	**4,781,773**	**1,768,613**
	TOTAL OPERATING EXPENSES	**132,316,508**	**71,192,299**	**67,751,168**	**11,343,480**
	Memo: SEC Total Operating Expenses	**348,814,493**	**297,287,292**	**284,249,152**	**11,343,481**
	OPERATING INCOME	**90,878,539**	**14,532,892**	**37,882,701**	**38,462,946**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	22,745	9,044	11,263	2,438
	Interest & Dividend NonAffiliated	**22,745**	**9,044**	**11,263**	**2,438**
4190001	Interest Inc - Assoc Non CBP	14,193	14,193	0	0
4190005	Interest Income - Assoc CBP	11,446	3,021	(28,807)	37,232
	Interest & Dividend Affiliated	**25,639**	**17,214**	**(28,807)**	**37,232**
	Total Interest & Dividend Income	**48,384**	**26,258**	**(17,544)**	**39,670**
4210039	Carrying Charges	31,720	0	0	31,720
	Interest & Dividend Carrying Charge	**31,720**	**-**	**-**	**31,720**
	Memo: Total Interest & Dividend Income w/ Carrying	**80,104**	**26,258**	**(17,544)**	**71,390**
4191000	Allw Oth Fnds Usd Drng Cnstr	2,716,016	230,631	1,709,809	775,576
	AFUDC	**2,716,016**	**230,631**	**1,709,809**	**775,576**
	Gain on Disposition of Equity Investments	**-**	**-**	**-**	**-**
	Interest LTD FMB	**-**	**-**	**-**	**-**
4270002	Int on LTD - Install Pur Contr	801	801	0	0
	Interest LTD IPC	**801**	**801**	**-**	**-**
4300001	Interest Exp - Assoc Non-CBP	525,000	204,805	160,889	159,306
	Interest LTD Notes Payable - Affiliated	**525,000**	**204,805**	**160,889**	**159,306**
	Interest LTD Notes Payable - NonAffiliated	**-**	**-**	**-**	**-**
	Interest LTD Debentures	**-**	**-**	**-**	**-**
4270006	Int on LTD - Sen Unsec Notes	16,999,353	6,631,533	5,209,537	5,158,284
	Interest LTD Senior Unsecured	**16,999,353**	**6,631,533**	**5,209,537**	**5,158,284**
4270012	PCRB Interest Exp-Assoc	14,193	14,193	0	0
	Interest LTD Other - Affil	**14,193**	**14,193**	**-**	**-**
4270005	Int on LTD - Other LTD	1,446,875	1,453,472	(6,597)	0
	Interest LTD Other - NonAffil	**1,446,875**	**1,453,472**	**(6,597)**	**-**
	Interest on Long-Term Debt	**18,986,223**	**8,304,804**	**5,363,829**	**5,317,590**
4300003	Int to Assoc Co - CBP	28,026	4,289	169,411	(145,673)
	Interest STD - Affil	**28,026**	**4,289**	**169,411**	**(145,673)**
4310007	Lines Of Credit	379,608	154,745	189,606	35,257
	Interest STD - NonAffil	**379,608**	**154,745**	**189,606**	**35,257**
	Interest on Short Term Debt	**407,635**	**159,034**	**359,017**	**(110,416)**
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	235,593	91,906	72,199	71,488
	Amort of Debt Disc. Prem & Exp	**235,593**	**91,906**	**72,199**	**71,488**
4281004	Amrtz Loss Rcquired Debt-Obnt	16,824	6,563	5,156	5,105
	Amort Loss on Reacquired Debt	**16,824**	**6,563**	**5,156**	**5,105**
	Amort Gain on Reacquired Debt	**-**	**-**	**-**	**-**

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jun 2014
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Layout: GLS8016

09B V2014-06-30	Account: GL_ACCT_SEC Business Units: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Jun 2014	Kentucky Power Company - Distribution 110 Actual YTD Jun 2014	Kentucky Power Company - Generation 117 Actual YTD Jun 2014	Kentucky Power Company - Transmission 180 Actual YTD Jun 2014
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	68,244	20,228	41,494	6,522
4310002	Interest on Customer Deposits	14,259	14,259	0	0
4310023	Interest Expense - State Tax	2,203	1,098	1,052	53
	Other Interest - NonAffil	**84,706**	**35,585**	**42,546**	**6,575**
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(1,389,378)	(114,308)	(879,754)	(395,317)
	AFUDC-Borrowed Funds	**(1,389,378)**	**(114,308)**	**(879,754)**	**(395,317)**
	Total Interest Charges	**18,341,603**	**8,483,585**	**4,962,992**	**4,895,026**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**75,333,057**	**6,306,197**	**34,611,974**	**34,414,886**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	25,140,436	3,376,677	12,039,188	9,724,571
4092001	Inc Tax, Oth Inc&Ded-Federal	(299,868)	(215,511)	(51,459)	(32,898)
	Federal Current Income Tax	**24,840,568**	**3,161,166**	**11,987,729**	**9,691,673**
4101001	Prov Def I/T Util Op Inc-Fed	25,128,423	2,665,965	20,521,681	1,940,778
4102001	Prov Def I/T Oth I&D - Federal	308,314	187,627	85,594	35,093
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(26,661,255)	(3,899,948)	(22,010,167)	(751,140)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(40,885)	0	(40,885)	0
	Federal Deferred Income Tax	**(1,265,403)**	**(1,046,356)**	**(1,443,777)**	**1,224,731**
4114001	ITC Adj, Utility Oper - Fed	(48,019)	(7,560)	(11,556)	(28,903)
	Federal Investment Tax Credits	**(48,019)**	**(7,560)**	**(11,556)**	**(28,903)**
	Federal Income Taxes	**23,527,146**	**2,107,249**	**10,532,396**	**10,887,501**
409100214	Income Taxes UOI - State	4,357,360	234,441	2,429,511	1,693,409
409200214	Inc Tax Oth Inc Ded - State	(52,048)	(37,406)	(8,932)	(5,710)
	State Current Income Tax	**4,305,312**	**197,035**	**2,420,579**	**1,687,698**
4111002	Prv Def I/T-Cr UtilOpInc-State	(305,760)	0	(305,760)	0
	State Deferred Income Tax	**(305,760)**	-	**(305,760)**	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	**3,999,552**	**197,035**	**2,114,819**	**1,687,698**
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	**27,526,698**	**2,304,284**	**12,647,215**	**12,575,199**
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**47,806,359**	**4,001,913**	**21,964,759**	**21,839,687**
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	**47,806,359**	**4,001,913**	**21,964,759**	**21,839,687**
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	**47,806,359**	**4,001,913**	**21,964,759**	**21,839,687**
	NET INCOME (LOSS) NODE before PS	**47,806,359**	**4,001,913**	**21,964,759**	**21,839,687**
	Double Check on Net Income Node after PS	(0)	0	0	-

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Jun 2014
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Layout : GLS8216

09B V2014-06- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Jun 2014	YTD Jun 2014	YTD Jun 2014	YTD Jun 2014
ASSETS				
Cash and Cash Equivalents	828,240	828,240	0	0
Other Cash Deposits	0	0	0	0
Customers	20,289,597	6,364,316	11,850,633	2,074,648
Accrued Unbilled Revenues	9,678	(381,389)	391,067	0
Miscellaneous Accounts Receivable	28,533,609	21,611,315	176,020,578	11,270,364
Allowances for Uncollectible Accounts	(28,541)	(16,914)	(11,628)	0
Accounts Receivable	48,804,343	27,577,329	188,250,651	13,345,012
Advances to Affiliates	49,347,801	69,742,313	(146,832,906)	126,438,394
Fuel, Materials and Supplies	63,441,586	2,333,712	60,205,481	902,393
Risk Management Contracts - Current	5,388,954	(310)	5,389,264	0
Margin Deposits	820,506	32,226	788,280	0
Unrecovered Fuel - Current	10,174,570	0	10,174,570	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	2,646,724	2,413,671	194,979	38,074
TOTAL CURRENT ASSETS	181,452,723	102,927,181	118,170,318	140,723,873
Electric Production	1,137,929,576	751,389,346	1,601,565,474	509,259,972
Electric Transmission	512,625,105	0	0	0
Electric Distribution	706,035,506	0	0	0
General Property, Plant and Equipment	511,154,041	199,571	4,169,386	1,160,479
Construction Work-in-Progress	93,023,178	15,702,428	35,899,758	41,420,992
TOTAL PROPERTY, PLANT and EQUIPMENT	2,960,767,405	767,291,344	1,641,634,618	551,841,443
less: Accumulated Depreciation and Amortization	(982,243,236)	(241,487,742)	(570,574,287)	(170,181,206)
NET PROPERTY, PLANT and EQUIPMENT	1,978,524,170	525,803,602	1,071,060,331	381,660,237
Net Regulatory Assets	213,988,813	101,946,424	56,376,611	55,665,778
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	1,638,523	(79)	1,638,602	0
Employee Benefits and Pension Assets	15,900,972	112,290	15,336,774	451,908
Other Non Current Assets	10,911,850	4,399,814	4,330,787	2,181,249
TOTAL OTHER NON-CURRENT ASSETS	242,440,158	106,458,448	77,682,774	58,298,936
TOTAL ASSETS	2,402,417,052	735,189,231	1,266,913,423	580,683,045
LIABILITIES				
Accounts Payable	83,184,701	172,734,950	70,476,290	20,342,110
Advances from Affiliates	0	0	0	0
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	265,000,000	0	265,000,000	0
Long-Term Debt Due Within One Year - Affiliated	20,000,000	7,063,600	7,356,600	5,579,800
Risk Management Liabilities	884,387	0	884,387	0
Accrued Taxes	32,423,489	7,767,782	7,995,158	16,660,549
Memo: Property Taxes	13,582,152	6,139,966	3,656,243	3,785,943
Accrued Interest	6,627,371	2,342,254	2,457,412	1,827,705
Risk Management Collateral	323,557	16,496	307,061	0
Utility Customer Deposits	24,662,061	24,662,061	0	0
Deposits - Customer and Collateral	24,985,618	24,678,556	307,061	0
Over-Recovered Fuel Costs - Current	0	0	0	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,158,006	510,174	504,231	143,601
Tax Collections Payable	2,397,340	2,296,514	93,609	7,217
Revenue Refunds - Accrued	1,159,596	0	40,000	1,119,596
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	1,029,458	378,747	599,109	51,603
Accrued Rents	0	0	0	0

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Jun 2014
07/09/2014 14:57

Layout : GLS8216

09B V2014-06-	Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS	Kentucky Power Int Consol GLS8216 YTD Jun 2014	Kentucky Power Company - 110 YTD Jun 2014	Kentucky Power Company - Generation 117 YTD Jun 2014	Kentucky Power Company - 180 YTD Jun 2014
	Accrued ICP	4,040,421	1,637,944	2,256,037	146,440
	Accrued Vacations	5,485,550	2,126,340	3,091,769	267,440
	Misc Employee Benefits	1,261,379	484,632	771,026	5,721
	Payroll Deductions	225,614	101,506	109,460	14,649
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	739,418	325,912	392,998	20,508
2530022	Customer Advance Receipts	1,194,121	1,194,121	0	0
	Customer Advance	1,194,121	1,194,121	0	0
2420511	Control Cash Disburse Account	1,991,634	1,991,634	0	0
	Control Cash Disbursement Account	1,991,634	1,991,634	0	0
	JMG Liability	0	0	0	0
2420088	Econ Development Fund Curr	349,500	0	349,500	0
2420506	Est Financing Cost - Bonds	(32,478)	0	(32,478)	0
2420512	Unclaimed Funds	7,416	7,416	0	0
2420542	Acc Cash Franchise Req	85,871	85,871	0	0
242059214	Sales Use Tax - Lease Equip	190	0	151	39
2420643	Accrued Audit Fees	15,915	331	15,383	201
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	246,141	0	246,141	0
2530050	Deferred Rev -Pole Attachments	43,128	43,128	0	0
2530112	Other Deferred Credits-Curr	227,650	6,033	221,616	0
2530124	Contr in Aid of Constr Advance	40,020	40,020	0	0
2530177	Deferred Rev-Bonus Lease Curr	431,564	0	431,564	0
	Misc Current and Accrued Liabilities	1,969,244	182,799	1,786,205	241
	Current Other and Accrued Liabilities	21,493,775	10,720,150	9,140,212	1,633,414
	Other Current Liabilities	22,651,781	11,230,323	9,644,442	1,777,015
	TOTAL CURRENT LIABILITIES	455,757,347	225,817,466	364,121,350	46,187,179
	Long-Term Debt - Affiliated	0	0	0	0
	Long-Term Debt - Non Affiliated	530,000,000	187,185,400	194,949,900	147,864,700
	Long-Term Debt - Premiums and Discounts Unamort	(527,963)	(186,466)	(194,201)	(147,296)
	Memo - LTD NonAffiliated and Premiums	*529,472,038*	*186,998,934*	*194,755,699*	*147,717,404*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	774,123	0	774,123	0
	Long-Term Risk Management Liabilities - MTM	774,123	0	774,123	0
	Long-Term Risk Management Liabilities	774,123	0	774,123	0
	Deferred Income Taxes	553,864,087	168,325,722	266,284,329	119,254,036
	Deferred Investment Tax Credits	77,728	16,605	26,272	34,852
	Regulatory Liabilities and Deferred Credits	23,966,591	(32,258,801)	62,596,703	(6,371,312)
	Memo - Reg Liab and Def ITC	*24,044,319*	*(32,242,196)*	*62,622,975*	*(6,336,460)*
	Asset Retirement Obligation	63,370,780	62,717	63,308,063	0
	Nuclear Decommissioning	0	0	0	0
	Employee Benefits and Pension Obligations	7,681,088	2,963,768	4,620,418	96,902
	Trust Preferred Securities	0	0	0	0
	Cumulative Preferred Stocks of Subs - Mandatory Red	0	0	0	0
	Obligations Under Capital Leases	3,623,426	1,402,901	1,761,172	459,353
	Def Credits - Income Tax	683,714	362,465	278,593	42,656
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	116,873	116,873	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	5,140	0	5,140	0
2530067	IPP - System Upgrade Credits	273,193	0	0	273,193
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	153,700	153,700	0	0
2530137	Fbr Opt Lns-Sold-Dafd Rev	96,396	0	0	96,396
2530178	Deferred Rev-Bonus Lease NC	1,654,329	0	1,654,329	0
	Def Credits - Other	2,182,757	153,700	1,659,469	369,588
	Total Other Deferred Credits	2,299,630	270,573	1,659,469	369,588
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	815,500	0	815,500	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Jun 2014
07/09/2014 14 57

Layout : GLS8216

09B V2014-06- Account: GL_ACCT_SEC Business Unit: REGIONAL_A_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Jun 2014	YTD Jun 2014	YTD Jun 2014	YTD Jun 2014
Other Non-Current Liabilities	8,532,913	2,035,938	5,625,378	871,597
TOTAL NON-CURRENT LIABILITIES	1,187,739,348	328,144,883	597,990,986	261,603,478
TOTAL LIABILITIES	1,643,496,694	553,962,349	962,112,336	307,790,657
Cumulative Pref Stocks of Subs - Not subject Mand Rede	0	0	0	0
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS' EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	517,459,453	106,025,371	327,394,246	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	197,497,283	52,865,037	(26,515,339)	171,147,585
Accumulated Other Comprehensive Income (Loss)	(6,486,379)	(67,576)	(6,365,423)	(53,380)
TOTAL SHAREHOLDERS' EQUITY	758,920,357	181,226,882	304,801,087	272,892,388
Memo: Total Equity	758,920,357	181,226,882	304,801,087	272,892,388
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	2,402,417,052	735,189,231	1,266,913,423	580,683,045
out-of-balance	(0)	0	0	(0)

Reserved Section

Kentucky Power Corp Consol
Comparative Balance Sheet
June 30, 2013

Run Date: 07/09/2013 19:19

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V KYP_CORP_CI V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
ASSETS			
PRODUCTION	560,291,983.53	558,934,668.00	1,357,315.53
TRANSMISSION	491,244,101.82	490,152,082.00	1,092,019.82
DISTRIBUTION	670,751,770.72	652,615,328.83	18,136,441.89
GENERAL	60,048,699.53	57,451,300.18	2,597,399.35
CONSTRUCTION WORK IN PROGRESS	49,072,108.54	44,281,291.91	4,790,816.63
ELECTRIC UTILITY PLANT	**1,831,408,664.14**	**1,803,434,670.92**	**27,973,993.22**
less Accum Provision - Depre, Depl, Amort.	(642,578,519.74)	(624,238,902.51)	(18,339,617.23)
NET ELECTRIC UTILITY PLANT	**1,188,830,144.40**	**1,179,195,768.41**	**9,634,375.99**
Net NonUtility Property	2,655,542.69	5,498,717.60	(2,843,174.91)
Investment in Subsidiary & Associated	0.00	0.00	0.00
Other Investments	257,889.67	260,727.67	(2,838.00)
Other Special Funds	0.00	0.00	0.00
Allowance - NonCurrent	2,361,233.00	2,361,232.37	0.63
Long Term Energy Trading Contracts	4,864,432.21	6,881,654.77	(2,017,222.56)
OTHER PROPERTY AND INVESTMENTS	**10,139,097.57**	**15,002,332.41**	**(4,863,234.84)**
Cash and Cash Equivalents	1,360,304.07	1,925,747.09	(565,443.02)
Advances to Affiliates	4,600,407.43	0.00	4,600,407.43
Acct Rec - Customers	15,459,580.18	12,676,052.64	2,783,527.54
Acct Rec - Miscellaneous	1,385,987.57	3,141,697.43	(1,755,709.86)
Acct Rec - AP for Uncollectible Accounts	(18,278.76)	(141,538.08)	123,259.32
Acct Rec - Associated Companies	6,341,860.36	9,241,088.58	(2,899,228.22)
Fuel Stock	47,192,625.57	69,147,176.47	(21,954,550.90)
Materials and Supplies	21,406,062.10	25,061,279.42	(3,655,217.32)
Accrued Utility Revenues	319,568.55	816,939.53	(497,370.98)
Energy Trading	5,937,218.20	6,174,819.72	(237,601.52)
Prepayments	727,224.22	1,569,794.80	(842,570.58)
Other Current Assets	1,434,529.82	1,660,942.94	(226,413.12)
CURRENT ASSETS	**106,147,089.30**	**131,274,000.53**	**(25,126,911.23)**
REGULATORY ASSETS	**213,627,428.69**	**214,900,829.18**	**(1,273,400.49)**
TOTAL DEFERRED CHARGES	**69,210,229.69**	**78,498,798.33**	**(9,288,568.64)**
TOTAL ASSETS	**1,587,953,989.65**	**1,618,871,728.86**	**(30,917,739.21)**
CAPITALIZATION and LIABILITIES			
COMMON STOCK			
Authorized: 2,000,000 Shares			
Outstanding: 1,009,000 Shares			
Common Stock	50,450,000.00	50,450,000.00	0.00
Premium on Capital Stock	0.00	0.00	0.00
Paid-In-Capital	238,537,123.01	238,341,119.49	196,003.52
Retained Earnings	201,692,949.40	190,818,915.56	10,874,033.84
COMMON SHAREHOLDERS' EQUITY	**490,680,072.41**	**479,610,035.05**	**11,070,037.36**
PS Subject To Mandatory Redemption	0.00	0.00	0.00
PS Not Subject Mandatory Redemption	0.00	0.00	0.00

Kentucky Power Corp Consol
Comparative Balance Sheet
June 30, 2013

Run Date: 07/09/2013 19:19

X_OPR_COS / KYP_CORP_C(	Rpt ID: GLR2200V Layout: GLR2200V / V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
	CUMULATIVE PREFERRED STOCK	**0.00**	**0.00**	**0.00**
	TRUST PREFERRED SECURITIES	**0.00**	**0.00**	**0.00**
	Long-Term Debt Less Amt Due 1 Yr	**549,305,312.50**	**549,221,950.00**	**83,362.50**
	CAPITALIZATION	**1,039,985,384.91**	**1,028,831,985.05**	**11,153,399.86**
	Obligations Under Capital Lease-NonCurrent	1,884,605.14	1,674,300.89	210,304.25
	Accumulated Provision Rate Relief	0.00	1,635,430.00	(1,635,430.00)
	Accumlated Provision - Miscellanous	35,364,175.40	34,033,794.12	1,330,381.28
	Other NonCurrent Liabilities	**37,248,780.54**	**37,343,525.01**	**(94,744.47)**
	Preferred Stock Due Within 1 Year	0.00	0.00	0.00
	Long-Term Debt Due Within 1 Year	0.00	0.00	0.00
	Accumulated Provision Due Within 1 Year	0.00	0.00	0.00
	Short-Term Debt	0.00	0.00	0.00
	Advances from Affiliates	0.00	13,358,855.63	(13,358,855.63)
	A/P General	19,463,537.36	30,336,776.64	(10,873,239.28)
	A/P Associated Companies	30,456,150.48	41,052,680.18	(10,596,529.70)
	Customer Deposits	24,615,929.59	23,484,964.81	1,130,964.78
	Taxes Accrued	3,885,206.06	6,548,714.64	(2,663,508.58)
	Interest Accrued	6,378,411.26	7,166,695.02	(788,283.76)
	Dividends Accrued	0.00	0.00	0.00
	Obligation Under Capital Leases	1,246,833.16	1,403,875.95	(157,042.79)
	Energy Contracts Current	2,822,360.57	3,320,068.02	(497,707.45)
	Other Current and Accrued Liabilities	15,465,726.78	17,797,808.10	(2,332,081.32)
	Current Liabilities	**104,334,155.26**	**144,470,438.99**	**(40,136,283.74)**
	Deferred Income Taxes	**392,148,521.91**	**385,153,166.17**	**6,995,355.74**
	Deferred Investment Tax Credits	**240,754.30**	**355,758.82**	**(115,004.52)**
	Regulatory Liabilities	**7,084,863.51**	**13,831,965.72**	**(6,747,102.21)**
2440002	LT Unreal Losses - Non Affil	3,097,635.53	4,200,196.07	(1,102,560.54)
2440022	L/T Liability MTM Collateral	(217,432.00)	(582,545.00)	365,113.00
2450011	L/T Liability-Commodity Hedges	5,964.00	82,731.00	(76,767.00)
	Long-Term Energy Trading Contracts	2,886,167.53	3,700,382.07	(814,214.54)
2520000	Customer Adv for Construction	58,084.49	63,177.74	(5,093.25)
	Customer Advances for Construction	58,084.49	63,177.74	(5,093.25)
	Deferred Gains on Sale/Leaseback	0.00	0.00	0.00
	Deferred Gains on Dispostion of Utility Plant	0.00	0.00	0.00
2530000	Other Deferred Credits	0.00	0.00	0.00
2530022	Customer Advance Receipts	1,691,821.39	2,634,497.53	(942,676.14)
2530050	Deferred Rev -Pole Attachments	45,666.29	78,940.35	(33,274.06)
2530067	IPP - System Upgrade Credits	264,491.41	260,279.72	4,211.69
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	159,776.00	162,614.00	(2,838.00)
2530112	Other Deferred Credits-Curr	940,629.05	1,113,326.72	(172,697.67)
2530114	Federl Mitigation Deferal(NSR)	754,941.55	754,941.55	0.00

Kentucky Power Corp Consol
Comparative Balance Sheet
June 30, 2013

Run Date: 07/09/2013 19:19

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V KYP_CORP_C(V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS		Month End Balances 2013	December Balances Last Year	Variance $
2530137	Fbr Opt Lns-Sold-Defd Rev	109,951.52	116,729.42	(6,777.90)
	Other Deferred Credits	3,967,277.21	5,121,329.29	(1,154,052.08)
	Deferred Credits	**6,911,529.23**	**8,884,889.10**	(1,973,359.87)
	DEFERRED CREDITS & REGULATED LIABILITIES	**406,385,668.95**	**408,225,779.81**	(1,840,110.86)
	CAPITAL & LIABILITIES	**1,587,953,989.66**	**1,618,871,728.87**	(30,917,739.21)

Statement of Retained Earnings

	BALANCE AT BEGINNING OF YEAR	**190,818,915.56**	**171,840,462.36**	18,978,453.21
	Net Income (Loss)	23,374,033.84	50,978,453.21	(27,604,419.37)
	Deductions:			
	Dividend Declared On Common Stock	(12,500,000.00)	-32,000,000	19,500,000.00
	Dividend Declared On Preferred Stock	0.00	0	0.00
	Adjustment in Retained Earnings	0.00	0.00	(0.00)
	Total Deductions	(12,500,000.00)	(32,000,000.00)	19,500,000.00
	BALANCE AT END OF PERIOD (A)	**201,692,949.40**	**190,818,915.56**	10,874,033.84

(A) Represents The Following Balances At End Of Period

215.0	Appropriated Retained Earnings	0.00	0.00	0.00
215.1	Appr Retnd Erngs - Amrt Rsv, Fed	0.00	0.00	0.00
	Total Appropriated Retained Earnings	0.00	0.00	0.00
2160000-1	Unapprp Retained Earnings Unrestr	190,818,915.56	171,840,462.36	18,978,453.21
2160002+	Unapprp Retained Earnings Restr	0.00	0.00	0.00
210.0	Gain on Reacquired Pref Stock	0.00	0.00	0.00
	Net Income Transferred	10,874,033.84	18,978,453.21	(8,104,419.37)
	Total Unappropriated Retained Earnings	201,692,949.40	190,818,915.56	10,874,033.84
216.1	Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
418.1	Equity Earnings of Subsidiary Co	0.00	0.00	0.00
	Total Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
	Total Other Retained Earnings Accounts	(0.00)	0.00	(0.00)
	TOTAL RETAINED EARNINGS	**201,692,949.40**	**190,818,915.56**	10,874,033.84

Final 07/09/2014

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - June, 2014

GLR7210V 07/09/14 16:10

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	115,327,430.06	(2,382,777.26)	(9.12)	0.00	1,591,628,895.56
	TOTAL PRODUCTION	1,478,684,251.88	115,327,430.06	(2,382,777.26)	(9.12)	0.00	1,591,628,895.56
101/106	TRANSMISSION	503,165,571.80	5,397,794.84	(105,859.43)	0.00	0.00	508,457,507.21
101/106	DISTRIBUTION	733,776,590.81	17,864,398.18	(3,726,089.74)	0.00	0.00	747,914,899.25
	TOTAL (ACCOUNTS 101 & 106)	2,715,626,414.49	138,589,623.08	(6,214,726.43)	(9.12)	0.00	2,848,001,302.02
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	528,381.86	0.00	6,807,531.03
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	2,721,905,563.66	138,589,623.08	(6,214,726.43)	528,372.74	0.00	2,854,808,833.05
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	CONSTRUCTION WORK IN PROGRESS:						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		60,435,840.02				
107000X	TRANSFERS		(96,011,810.45)				
107000X	END. BAL.		(35,575,970.43)				93,023,177.76
	TOTAL ELECTRIC UTILITY PLANT	2,857,910,670.58	103,013,652.65	(6,214,726.43)	528,372.74	0.00	2,955,237,969.54
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	5,529,435.74	0.00	0.00	(0.03)	0.00	5,529,435.71

Acct 107 Transfers	(96,011,810.45)
Acct 101/6 Additions	138,589,623.08
	42,577,812.63
ARO - ASH#1 Big Sandy Ash Pond 06/2014	42,577,812.63

Prepared by: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee -- Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

Final 07/09/2014

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - June, 2014

GLR7410V

07/09/14 15:11

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	27,766,233.89	(2,382,777.26)	(1,565,138.90)	0.00	623,322,444.62
1080001/11	TRANSMISSION	161,537,795.16	4,331,193.60	(105,859.43)	(217,836.83)	0.00	165,545,292.50
1080001/11	DISTRIBUTION	192,744,660.64	12,661,293.73	(3,726,089.74)	(956,912.88)	0.00	200,722,951.75
1080013	PRODUCTION	(3,620,015.26)	0.00	0.00	0.00	(262,141.37)	(3,882,156.63)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698.85)	0.00	0.00	0.00	(4,589.42)	(31,288.27)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(3,227,681.92)	2,739,888.61	(8,808,045.83)
	TOTAL (108X accounts)	**941,819,616.07**	**44,758,721.22**	**(6,214,726.43)**	**(5,967,570.53)**	**2,473,157.82**	**976,869,198.15**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	672,473.19	0.00	0.00	84,795.27	11,186,619.33
1110001	TRANSMISSION	1,607,792.68	291,717.34	0.00	0.00	0.00	1,899,510.02
1110001	DISTRIBUTION	7,182,584.75	765,721.07	0.00	0.00	0.00	7,948,305.82
	TOTAL (111X accounts)	**19,219,728.30**	**1,729,911.60**	**0.00**	**0.00**	**84,795.27**	**21,034,435.17**
1011006	CAPITAL LEASES	1,869,467.09	0.00	0.00	0.00	156,632.64	2,026,099.73
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**962,908,811.46**	**46,488,632.82**	**(6,214,726.43)**	**(5,967,570.53)**	**2,714,585.73**	**999,929,733.05**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	214,955.75	3,334.86	0.00	0.00	0.00	218,290.61
1240027	Other Property - RWIP	(3,400.00)	0.00	0.00	0.00	0.00	(3,400.00)
	TOTAL NONUTILITY PLANT	**211,555.75**	**3,334.86**	**0.00**	**0.00**	**0.00**	**214,890.61**

Prepared by: PSnVision Report GLR7410V
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

August 20, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed July 2014 Financial Report pages for Kentucky Power Company consisting of the following:

<u>Income Statement:</u>

1-9	Income Statement
1-3	Details of Operating Revenues
4-7	Operating Expenses – Functional Expenses
~~8-9~~	~~Detail Statement of Taxes~~

<u>Balance Sheet:</u>

10	Balance Sheet – Assets & Other Debits
10-12	Balance Sheet – Liabilities & Other Credits
11-12	Deferred Credits
12	Statement of Retained Earnings

<u>Utility Property</u>:

13-14	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Brian J. Frantz
Manager – Regulated Accounting

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jul 2014
08/08/2014 15:18

Layout: GLS8016
09B V2014-07-31 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

Account		Description	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	74,065,517	74,715,979	(650,462)	0
4400002		Residential Sales-W/O Space Ht	32,548,565	32,968,710	(420,145)	0
4400005		Residential Fuel Rev	46,490,651	46,490,651	0	0
	A	**Revenue - Residential Sales**	**153,104,733**	**154,175,340**	**(1,070,607)**	-
4420001		Commercial Sales	45,248,251	45,481,505	(233,254)	0
4420006		Sales to Pub Auth - Schools	8,197,013	8,110,102	86,911	0
4420007		Sales to Pub Auth - Ex Schools	8,445,303	8,467,386	(22,083)	0
4420013		Commercial Fuel Rev	26,057,681	26,057,681	0	0
	A	**Revenue - Commercial Sales**	**87,948,249**	**88,116,674**	**(168,425)**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	37,190,920	37,256,998	(66,078)	0
4420004		Ind Sales-NonAffil(Incl Mines)	17,545,814	17,485,214	60,600	0
4420016		Industrial Fuel Rev	53,938,198	53,938,198	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**108,674,932**	**108,680,410**	**(5,478)**	-
		Revenue - Industrial Sales	**108,674,932**	**108,680,410**	**(5,478)**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	861,659	858,686	2,973	0
4440002		Public St & Hwy Light Fuel Rev	185,451	185,451	0	0
	A	**Revenue - Other Retail Sales**	**1,047,310**	**1,044,337**	**2,973**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**350,775,224**	**352,016,762**	**(1,241,538)**	-
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	20,458,476
4561033		PJM NITS Revenue - Affiliated	9,441,944	0	0	21,615,066
4561034		PJM TO Adm Serv Rev - Aff	0	0	0	349,212
4561035		PJM Affiliated Trans NITS Cost	(9,173,308)	0	(21,346,432)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(349,212)	0
4561059		Affil PJM Trans Enhancmnt Rev	131,564	0	0	239,784
4561060		Affil PJM Trans Enhancmnt Cost	(125,895)	0	(234,115)	0
4561062		PROVISION RTO Cost - Affl	(1,530,542)	0	(1,530,542)	0
4561063		PROVISION RTO Rev Affiliated	2,435,642	0	0	2,435,642
	B	**Revenue - Transmission-Affiliated**	**1,179,404**	-	**(23,460,302)**	**45,098,182**
4470150		Transm Rev -Dedic. Whsl/Muni	(12,356)	0	(440,790)	428,434
4470206		PJM Trans loss credits-OSS	1,494,459	0	1,494,459	0
4470207		PJM transm loss charges - LSE	(12,097,839)	0	(12,097,839)	0
4470208		PJM Transm loss credits-LSE	1,833,699	0	1,833,699	0
4470209		PJM transm loss charges-OSS	(12,025,449)	0	(12,025,449)	0
4561002		RTO Formation Cost Recovery	2,150	0	(82,898)	85,048
4561003		PJM Expansion Cost Recov	47,182	0	(51,361)	98,543
4561005		PJM Point to Point Trans Svc	414,458	0	414,458	0
4561006		PJM Trans Owner Admin Rev	166,937	0	0	166,937
4561007		PJM Network Integ Trans Svc	8,697,251	0	0	8,697,251
4561019		Oth Elec Rev Trans Non Affil	35,027	0	0	35,027
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	3,893	0	0	3,893
4561029		PJM NITS Revenue Whsl Cus-NAff	1,610,335	0	0	1,610,335
4561030		PJM TO Serv Rev Whls Cus-NAff	25,250	0	0	25,250
4561058		NonAffil PJM Trans Enhncmt Rev	241,751	0	0	241,751
4561061		NAff PJM RTEP Rev for Whsl-FR	17,885	0	0	17,885
4561064		PROVISION RTO Rev WhslCus-NAf	184,883	0	0	184,883
4561065		PROVISION RTO Rev - NonAff	1,065,770	0	0	1,065,770
	A	**Revenue - Transmission-NonAffiliated**	**(8,294,716)**	-	**(20,955,722)**	**12,661,006**
		Revenue - Transmission	**(7,115,312)**	-	**(44,416,024)**	**57,759,188**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	262	0	262	0
4470128		Sales for Res-Aff. Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,479,520**	-	**5,479,520**	-
4470002		Sales for Resale - NonAssoc	3,131	0	3,131	0
4470006		Sales for Resale-Bookout Sales	10,467,675	0	10,467,675	0
4470010		Sales for Resale-Bookout Purch	(10,916,326)	0	(10,916,326)	0
4470027		Whsal/Muni/Pu Ath Fuel Rev	1,675,019	0	1,675,019	0
4470028		Sale/Resale - NA - Fuel Rev	151,564	0	151,564	0
4470033		Whsal/Muni/Pub Auth Base Rev	2,797,339	0	2,797,339	0
4470066		PWR Trdng Trans Exp-NonAssoc	(116)	0	(116)	0
4470081		Financial Spark Gas - Realized	32,347	0	32,347	0
4470082		Financial Electric Realized	2,150,182	0	2,150,182	0
4470089		PJM Energy Sales Margin	97,491,189	0	97,491,189	0
4470093		PJM Implicit Congestion-LSE	(17,803,579)	0	(17,803,579)	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jul 2014
08/08/2014 15 16

Layout: GLS8016

09B V2014-07-31		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
4470098		PJM Oper Reserve Rev-OSS	(2,836,056)	0	(2,836,056)	0
4470099		Capacity Cr Net Sales	319,068	0	319,068	0
4470100		PJM FTR Revenue-OSS	622,050	0	622,050	0
4470101		PJM FTR Revenue-LSE	8,230,948	0	8,230,948	0
4470103		PJM Energy Sales Cost	110,775,088	0	110,775,088	0
4470106		PJM Pt2Pt Trans Purch-NonAff	(27)	0	(27)	0
4470107		PJM NITS Purch-NonAff	17,483	0	17,483	0
4470109		PJM FTR Revenue-Spec	(32,888)	0	(32,888)	0
4470110		PJM TO Admin Exp-NonAff	35,173	0	35,173	0
4470112		Non-Trading Bookout Sales-OSS	4,943	0	4,943	0
4470115		PJM Meter Corrections-OSS	(9,513)	0	(9,513)	0
4470116		PJM Meter Corrections-LSE	41,375	0	41,375	0
4470124		PJM Incremental Spot-OSS	1	0	1	0
4470126		PJM Incremental Imp Cong-OSS	(26,302,348)	0	(26,302,348)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	815,898	0	815,898	0
4470144		Realiz Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim Margin Reclass	(175)	0	(175)	0
4470168		Interest Rate Swaps Power	(9,493)	0	(9,493)	0
4470170		Non-ECR Auction Sales-OSS	1,386,855	0	1,386,855	0
4470174		PJM Whse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	231,970	0	231,970	0
4470176		OSS Sharing Reclass-Reduction	(231,970)	0	(231,970)	0
4470180		Trading intra-book Reclass	(119,770)	0	(119,770)	0
4470181		Auction intra-book Reclass	119,770	0	119,770	0
4470202		PJM OpRes-LSE-Credit	642,660	0	642,660	0
4470203		PJM OpRes-LSE-Charge	(4,671,469)	0	(4,645,111)	(26,358)
4470204		PJM Spinning-Credit	(0)	0	(0)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,200	0	28,200	0
4470220		PJM Regulation - OSS	112,392	0	112,392	0
4470221		PJM Spinning Reserve - OSS	9,976	0	9,976	0
4470222		PJM Reactive - OSS	362,920	0	362,920	0
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	(10,423)	0	(10,423)	0
5550080		PJM Hourly Net Purch -FERC	(24,359,993)	0	(24,359,993)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**151,222,688**	-	**151,249,046**	**(26,358)**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**156,702,208**	-	**156,728,566**	**(26,358)**
4470074		Sale for Resale-Aff-Trnf Price	0	0	262,598,284	0
4540001		Rent From Elect Property - Af	152,103	453,472	0	0
4560001		Oth Elect Rev - Affiliated	25,574	0	25,574	0
	B	**Revenue - Other Ele-Affiliated**	**177,676**	**453,472**	**262,623,858**	-
4500000		Forfeited Discounts	2,315,900	2,315,900	0	0
4510001		Misc Service Rev - Nonaffil	224,620	216,713	0	7,908
4540002		Rent From Elect Property-NAC	62,589	1,500	57,489	3,600
4540005		Rent from Elec Prop-Pole Attch	2,666,501	2,666,501	0	0
4560007		Oth Elect Rev - DSM Program	3,391,424	3,391,424	0	0
		Revenue - Other Ele-NonAffiliated	**8,661,034**	**8,592,038**	**57,489**	**11,508**
		Revenue - Gas	-	-	-	-
4118002		Comp Allow Gains Title IV SO2	383	0	383	0
4118004		Comp Allow Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,916**	-	**8,916**	-
	A	**Revenue - Other Ele-NonAffiliated**	**8,669,950**	**8,592,038**	**66,405**	**11,508**
		Revenue - Other Opr Electric	**8,847,626**	**9,045,510**	**262,690,263**	**11,508**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operating Rental Income	19,200	18,500	700	0
4180003		Non-Oprating Rntal Inc-Maint	(16)	0	(16)	0
4180005		Non-Oprating Rntal Inc Depr	(3,891)	0	0	(3,891)
	D	**Non-Operating Rental Income - NonAffiliated**	**15,294**	**18,500**	**684**	**(3,891)**
		Non-Operating Rental Income	**15,294**	**18,500**	**684**	**(3,891)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	1,312	412	543	357

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jul 2014
08/08/2014 15:18
Layout: GLS8016
09B V2014-07-31 Account: GL_ACCT_SEC Business Units: SEGMENT_CORS

Account	Code	Description	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
4210007		Misc Non-Op Inc - NonAsc - Oth	108,506	458	108,048	0
	D	**Non-Operating Misc Income - NonAffiliated**	**109,817**	**870**	**108,590**	**357**
		Non-Operating Misc Income	**109,817**	**870**	**108,590**	**357**
4540004		Rent From Elect Prop-ABD-Nonaf	48,945	48,945	0	0
4560015		Other Electric Revenues - ABD	149,769	133,542	0	16,227
	D	**Associated Business Development Income**	**198,714**	**182,487**	**-**	**16,227**
		Revenue - Other Opr - Other	**323,825**	**201,857**	**109,275**	**12,694**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***323,825***	***201,857***	***109,275***	***12,694***
		Revenue - Other Operating	**9,171,452**	**9,247,367**	**262,799,537**	**24,201**
	A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	-	-	-	-
4210031		Pwr Sales Outside Svc Territry	51,759	0	51,759	0
4210032		Pwr Purch Outside Svc Territry	(555)	0	(555)	0
	A	**Revenue - Power Sales**	**51,204**	**-**	**51,204**	**-**
		TOTAL OPERATING REVENUES	**509,584,776**	**361,264,129**	**373,921,746**	**57,757,031**
=(A)		*Memo: G/T/D Revenue*	*502,424,350*	*360,608,800*	*129,169,395*	*12,648,155*
=(B)		*Memo: Other Affiliated Revenue*	*6,836,601*	*453,472*	*244,643,076*	*45,098,182*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Non*	*323,825*	*201,857*	*109,275*	*12,694*
		Memo: Total Operating Revenues	*509,584,776*	*361,264,129*	*373,921,746*	*57,757,031*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***6,836,601***	***453,472***	***244,643,076***	***45,098,182***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***502,748,176***	***360,810,657***	***129,278,670***	***12,658,849***
		Memo: Total Operating Revenues	***509,584,776***	***361,264,129***	***373,921,746***	***57,757,031***
		FUEL EXPENSES				
5010000		Fuel	763,226	6	763,217	3
5010001		Fuel Consumed	169,854,277	0	169,854,277	0
5010003		Fuel - Procure Unload & Handle	7,519,216	0	7,519,216	0
5010013		Fuel Survey Activity	(734,602)	0	(734,602)	0
5010019		Fuel Oil Consumed	4,007,630	0	4,007,630	0
5010027		Gypsum handling/disposal costs	240,955	0	240,955	0
5010028		Gypsum Sales Proceeds	(450,191)	0	(450,191)	0
5470004		Fuel - Gas Turb - Purch / Hand	93	2	90	2
		Fuel Expense Total	**181,200,604**	**8**	**181,200,591**	**5**
5010005		Fuel - Deferred	(13,352,444)	0	(13,352,444)	0
		Deferred Fuel Expense	**(13,352,444)**	**-**	**(13,352,444)**	**-**
		Over Under Fuel Expense				
		Fuel for Electric Generation	**167,848,160**	**8**	**167,848,147**	**5**
5010029		Gypsum handling/displ-Affiliat	92,146	0	92,146	0
		Fuel from Affiliates for Electric Generation	**92,146**	**-**	**92,146**	**-**
5090000		Allow Consum Title IV SO2	5,600,183	0	5,600,183	0
5090001		Allowance Consumption - NOx	19,912	0	19,912	0
5090005		An. NOx Cons. Exp	81,735	0	81,735	0
		Allowances - Consumption	**5,701,830**	**-**	**5,701,830**	**-**
5020002		Urea Expense	3,284,318	0	3,284,318	0
5020003		Trona Expense	212,656	0	212,656	0
5020004		Limestone Expense	2,519,745	0	2,519,745	0
5020005		Polymer expense	51,861	0	51,861	0
5020007		Lime Hydrate Expense	9,436	0	9,436	0
		Emissions Control - Chemicals	**6,078,016**	**-**	**6,078,016**	**-**
		Total Fuel for Electric Generation	**179,720,152**	**8**	**179,720,139**	**5**
		Memo: NonAff Fuel/Allow/Emissions	***179,628,005***	***8***	***179,627,993***	***5***
5550004		Purchased Power-Pool Capacity	181,949	0	181,949	0
5550005		Purchased Power - Pool Energy	676,093	0	676,093	0
5550027		Purch Pwr-Non-Fuel Portion-Aff	28,475,353	0	28,475,353	0
5550029		Purch Power-Assoc Trnsfr Price	0	262,598,284	0	0
5550046		Purch Power-Fuel Portion-Affil	38,827,352	0	38,827,352	0
5550101		Purch Power-Pool Non-Fuel -Aff	168,508	0	168,508	0
5550102		Pur Power Pool NonFuel-OSS-Aff	214,985	0	214,985	0
		Purchased Electricity from AEP - Affiliates	**68,544,240**	**262,598,284**	**68,544,240**	**-**
5550000		Purchased Power	156	0	136	20
5550001		Purch Pwr-NonTrading-Nonassoc	498,135	0	498,135	0
5550032		Gas-Conversion-Mone Plant	3,274	0	3,274	0
5550039		PJM Inadvertent Mtr Res-OSS	(62,321)	0	(62,321)	0
5550040		PJM Inadvertent Mtr Res-LSE	(30,101)	0	(30,101)	0
5550041		PJM Ancillary Serv -Sync	5,492	0	5,492	0
5550074		PJM Reactive-Charge	(11,793)	0	(11,793)	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jul 2014
08/08/2014 15:18

Layout: GLS8016

09B V2014-07-31	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
5550076	PJM Black Start-Charge	878,703	0	878,703	0
5550077	PJM Black Start-Credit	(7)	0	(7)	0
5550078	PJM Regulation-Charge	1,586,582	0	1,586,582	0
5550079	PJM Regulation-Credit	(380,002)	0	(380,002)	0
5550083	PJM Spinning Reserve-Charge	1,321,682	0	1,321,682	0
5550084	PJM Spinning Reserve-Credit	(320,390)	0	(320,390)	0
5550090	PJM 30m Suppl Rserv Charge LSE	386,629	0	386,629	0
5550099	PJM Purchases-non-ECR-Auction	1,468,818	0	1,468,818	0
5550100	Capacity Purchases-Auction	49,120	0	49,120	0
5550107	Capacity purchases - Trading	133,535	0	133,535	0
	Purchased Electricity for Resale - NonAffiliated	**5,527,512**	-	**5,527,492**	**20**
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	**74,071,752**	**282,598,284**	**74,071,732**	**20**
	GROSS MARGIN	**255,792,873**	**98,665,837**	**120,129,875**	**57,757,006**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	2,214,901	116	2,214,688	97
5000001	Oper Super & Eng-RATA-Affl	50,962	0	50,962	0
5020000	Steam Expenses	1,501,884	0	1,501,884	0
5050000	Electric Expenses	336,577	0	336,577	0
5060000	Misc Steam Power Expenses	4,771,149	116	4,770,903	129
5060002	Misc Steam Power Exp-Assoc	33,824	0	33,824	0
5060003	Removal Cost Expense - Steam	(77,138)	0	(77,138)	0
5060004	NSR Settlement Expense	(1,427)	0	(1,427)	0
5060025	Misc Stm Pwr Exp Environmental	(11)	0	(11)	0
	Steam Generation Op Exp	**8,830,721**	**233**	**8,830,262**	**226**
	Nuclear Generation Op Exp	-	-	-	-
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	316,614	1	316,546	65
5570000	Other Expenses	1,026,294	1,208	1,024,289	797
5570007	Other Pwr Exp - Wholesale RECs	12,054	12,054	0	0
5570008	Other Pwr Exp - Voluntary RECs	10	10	0	0
5757000	PJM Admin-MAM&SC- OSS	344,559	0	344,559	0
5757001	PJM Admin-MAM&SC- Internal	445,045	0	445,045	(0)
	Other Generation Op Exp	**2,144,576**	**13,273**	**2,130,441**	**862**
5600000	Oper Supervision & Engineering	623,144	2,120	3,592	617,432
5611000	Load Dispatch - Reliability	5,077	0	0	5,077
5612000	Load Dispatch-Mntr&Op TransSys	511,660	45	75	511,541
5614000	PJM Admin-SSC&DS-OSS	308,895	0	308,895	0
5614001	PJM Admin-SSC&DS-Internal	394,632	0	394,632	0
5614007	RTO Admin Default LSE	3,874	0	3,539	335
5614008	PJM Admin Defaults OSS	2,417	0	2,417	0
5615000	Reliability Plng&Stds Develop	58,953	4,632	7,318	47,003
5618000	PJM Admin-RP&SDS-OSS	77,536	0	77,536	0
5618001	PJM Admin-RP&SDS- Internal	98,373	0	98,373	0
5620001	Station Expenses - Nonassoc	223,956	0	0	223,956
5630000	Overhead Line Expenses	94,166	0	0	94,166
5640000	Underground Line Expenses	4	0	0	4
5650002	Transmssn Elec by Others-NAC	113,599	0	113,599	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	20,458,476	0	0
5650012	PJM Trans Enhancement Charge	2,302,200	0	2,302,200	0
5650015	PJM TO Serv Exp - Aff	21,843	0	21,843	0
5650016	PJM NITS Expense - Affiliated	2,674,218	0	2,674,218	0
5650019	Affil PJM Trans Enhncement Exp	166,738	0	166,738	0
5650020	PROVISION RTO Affl Expense	1,148,824	0	1,148,824	0
5660000	Misc Transmission Expenses	781,684	6,086	8,440	767,158
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	301,370
5757002	SPP Admin-MAM&SC	0	0	0	0
	Transmission Op Exp	**9,612,044**	**20,471,359**	**7,332,240**	**2,568,291**
5800000	Oper Supervision & Engineering	396,318	388,822	2,215	5,281
5810000	Load Dispatching	2,325	1,772	0	553
5820000	Station Expenses	130,151	124,574	0	5,577
5830000	Overhead Line Expenses	565,344	565,468	(135)	11
5840000	Underground Line Expenses	61,215	61,043	126	46
5841000	Oper of Energy Storage Equip	0	0	0	0
5850000	Street Lighting & Signal Sys E	91,637	91,637	0	0
5860000	Meter Expenses	470,693	469,390	991	313

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09B V2014-07-31	Account: GL_ACCT_SEC Business Units: SEGMENT_COMB	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
5870000	Customer Installations Exp	92,479	92,479	0	0
5880000	Miscellaneous Distribution Exp	2,240,985	2,218,820	5,113	17,052
5890001	Rents - Nonassociated	996,497	996,497	0	0
5890002	Rents - Associated	40,131	40,131	0	0
	Distribution Op Exp	**5,087,777**	**5,050,635**	**8,309**	**28,833**
9010000	Supervision - Customer Accts	170,317	170,243	54	20
9020000	Meter Reading Expenses	4,873	4,538	244	91
9020001	Customer Card Reading	325	97	167	61
9020002	Meter Reading - Regular	257,073	257,073	0	0
9020003	Meter Reading - Large Power	32,327	32,327	0	0
9020004	Read-In & Read-Out Meters	33,751	33,751	0	0
9030000	Cust Records & Collection Exp	212,837	208,660	210	3,966
9030001	Customer Orders & Inquiries	1,497,966	1,497,217	571	178
9030002	Manual Billing	24,375	23,555	5	815
9030003	Postage - Customer Bills	463,582	463,582	0	0
9030004	Cashiering	88,345	87,735	312	298
9030005	Collection Agents Fees & Exp	32,680	32,680	0	0
9030006	Credit & Oth Collection Activi	439,612	439,563	36	12
9030007	Collectors	343,397	343,397	0	0
9030009	Data Processing	96,823	96,810	9	3
9040007	Uncoll Accts - Misc Receivable	(55,924)	(60,648)	4,725	0
9050000	Misc Customer Accounts Exp	17,522	17,522	0	0
9070000	Supervision - Customer Service	92,784	92,788	(2)	(2)
9070001	Supervision - DSM	(11)	(4)	(4)	(3)
9080000	Customer Assistance Expenses	280,225	280,234	(5)	(4)
9080001	DSM-Customer Advisory Grp	862	862	0	0
9080009	Cust Assistance Expense - DSM	2,791,801	2,791,012	569	221
9090000	Information & Instruct Advrtis	54,350	16,494	27,556	10,300
9100000	Misc Cust Svc&Informational Ex	20,272	8,327	8,865	3,080
	Customer Service and Information Op Exp	**6,900,163**	**6,837,815**	**43,311**	**19,037**
9120000	Demonstrating & Selling Exp	15,982	15,982	0	0
9120003	Demo & Selling Exp - Area Dev	(321)	(321)	0	0
	Sales Expenses	**15,660**	**15,660**	-	-
	Memo: Insurance (9240 9250)	**769,954**	**352,535**	**295,618**	**121,801**
9200000	Administrative & Gen Salaries	5,696,847	2,517,696	2,355,217	823,935
9210001	Off Supl & Exp - Nonassociated	471,198	286,567	145,279	39,351
9210003	Office Supplies & Exp - Trnsf	9	6	2	0
9220000	Administrative Exp Trnsf - Cr	(302,955)	(302,955)	0	(0)
9220001	Admin Exp Trnsf to Cnstrctn	(250,130)	(250,130)	0	0
9220004	Admin Exp Trnsf to ABD	(1,627)	(623)	0	(1,004)
9230001	Outside Svcs Empl - Nonassoc	774,406	346,678	318,778	108,950
9230002	Outside Svcs Empl - Assoc	(0)	0	(0)	0
9230003	AEPSC Billed to Client Co	(85,650)	(20,618)	(35,356)	(29,675)
9240000	Property Insurance	290,120	96,904	80,060	113,156
9250000	Injuries and Damages	692,280	483,876	173,859	34,545
9250001	Safety Dinners and Awards	3,126	1,403	1,375	349
9250002	Emp Accdent Prvntion-Adm Exp	5,397	3,367	1,426	604
9250004	Injuries to Employees	2,084	0	2,084	0
9250006	Wkrs Cmpnstn Pre&Slf Ins Prv	(178,207)	(137,655)	(24,760)	(15,793)
9250007	Prsnal Injries&Prop Dmage-Pub	67,208	684	66,511	14
9250010	Frg Ben Loading - Workers Comp	(112,054)	(96,043)	(4,937)	(11,075)
9260000	Employee Pensions & Benefits	2,735	2,735	0	0
9260001	Edit & Print Empl Pub-Salaries	14,901	5,378	6,135	3,387
9260002	Pension & Group Ins Admin	25,138	12,449	11,421	1,268
9260003	Pension Plan	2,937,621	1,337,941	1,440,076	159,604
9260004	Group Life Insurance Premiums	88,265	35,531	46,903	5,830
9260005	Group Medical Ins Premiums	2,969,407	1,475,750	1,263,268	230,389
9260006	Physical Examinations	1	0	0	1
9260007	Group L-T Disability Ins Prem	10,545	7,491	2,596	457
9260009	Group Dental Insurance Prem	142,976	73,130	60,397	9,450
9260010	Training Administration Exp	445	194	197	54
9260012	Employee Activities	1,607	571	486	550
9260014	Educational Assistance Pmts	987	900	0	87
9260019	Employee Benefit Exp - COLI	10,000	0	10,000	0
9260021	Postretirement Benefits - OPEB	(2,135,917)	(1,017,709)	(976,676)	(141,532)
9260027	Savings Plan Contributions	1,283,461	556,398	666,651	60,411
9260036	Deferred Compensation	4,437	4,437	0	0
9260037	Supplemental Pension	139	139	0	0
9260040	SFAS 112 Postemployment Benef	430,343	0	430,343	0
9260050	Frg Ben Loading - Pension	(879,366)	(613,939)	(207,298)	(58,128)

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09B V2014-07-31	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
9260051	Frg Ben Loading - Grp Ins	(1,040,955)	(725,952)	(227,617)	(87,387)
9260052	Frg Ben Loading - Savings	(416,392)	(256,038)	(126,737)	(33,617)
9260053	Frg Ben Loading - OPEB	263,424	212,008	23,979	27,437
9260055	IntercoFringeOffset- Don't Use	(1,021,464)	(224,858)	(701,441)	(95,164)
9260057	Postret Ben Medicare Subsidy	359,843	145,361	200,691	13,791
9260058	Frg Ben Loading - Accrual	(73,182)	(25,702)	(42,283)	(5,197)
9260060	Amort Post Retirement Benefit	126,362	75,589	41,537	9,236
9270000	Franchise Requirements	82,945	82,945	0	0
9280000	Regulatory Commission Exp	24,857	8,918	10,211	5,728
9280001	Regulatory Commission Exp-Adm	2	1	0	1
9280002	Regulatory Commission Exp-Case	83,908	19,135	52,088	12,685
9301000	General Advertising Expenses	848	298	362	187
9301001	Newspaper Advertising Space	9,064	3,267	3,765	2,033
9301002	Radio Station Advertising Time	4,435	1,605	1,834	997
9301010	Publicity	2,250	807	958	484
9301012	Public Opinion Surveys	16,310	16,306	0	4
9301015	Other Corporate Comm Exp	8,336	5,578	1,872	886
9302000	Misc General Expenses	138,665	72,419	37,226	29,020
9302003	Corporate & Fiscal Expenses	20,755	4,438	15,152	1,165
9302004	Research, Develop&Demonstr Exp	3,218	3,218	0	0
9302458	AEPSC Non Affiliated expenses	(0)	0	(0)	0
9310001	Rents - Real Property	55,395	55,395	0	0
9310002	Rents - Personal Property	150,284	100,494	43,102	6,687
	Administration & General	**10,778,685**	**4,385,784**	**5,168,739**	**1,224,162**
4111005	Accretion Expense	564,407	0	564,407	0
	Accretion	**564,407**	-	**564,407**	-
4116000	Gain From Disposition of Plant	(2,345)	(2,345)	0	0
	Loss/(Gain) on Utility Plant	**(2,345)**	**(2,345)**	-	-
9302006	Assoc Bus Dev - Materials Sold	31,321	31,321	0	0
9302007	Assoc Business Development Exp	54,601	32,069	23	22,508
	Associated Business Development Expenses	**85,922**	**63,390**	**23**	**22,508**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4265009	Factored Cust A/R Exp - Affil	556,172	556,172	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,088,607	1,088,607	0	0
	Opr Exp and Factored A/R	**1,644,779**	**1,644,779**	-	-
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	45,384	16,160	19,549	9,675
4265007	Regulatory Expenses	1,932	690	808	434
	Expense of Non-Utility Operation	**47,315**	**16,850**	**20,357**	**10,109**
4210009	Misc Non-Op Exp - NonAssoc	5,218	1,305	3,094	819
	Misc NonOp Expenses - NonAssoc	**5,218**	**1,305**	**3,094**	**819**
4261000	Donations	254,943	173,067	70,540	11,336
	Donation Contributions	**254,943**	**173,067**	**70,540**	**11,336**
4263001	Penalties	62,109	23,921	24,132	14,056
	Provision for Penalties	**62,109**	**23,921**	**24,132**	**14,056**
4264000	Civic & Political Activities	143,046	52,838	56,968	33,240
	Civic & Political Activities	**143,046**	**52,838**	**56,968**	**33,240**
4265002	Other Deductions - Nonassoc	318	95	164	59
4265033	Transition Costs	5,267	0	5,267	0
	Other Deductions	**5,585**	**95**	**5,430**	**59**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**2,162,995**	**1,912,856**	**180,520**	**69,620**
	Operational Expenses	**46,180,604**	**38,748,659**	**24,258,252**	**3,933,539**
5100000	Maint Supv & Engineering	2,225,186	185	2,224,973	28
5110000	Maintenance of Structures	1,036,378	0	1,036,378	0
5120000	Maintenance of Boiler Plant	10,228,567	(25)	10,228,592	0
5130000	Maintenance of Electric Plant	1,698,262	0	1,698,420	(158)
5140000	Maintenance of Misc Steam Plt	933,205	0	933,131	74
	Steam Generation Maintenance	**16,121,599**	**160**	**16,121,494**	**(56)**
5260000	Maint Supv & Engineering	485	0	485	0
	Nuclear Generation Maintenance	**485**	-	**485**	-
	Hydro Generation Maintenance	-	-	-	-
5530001	Maint of Gen Plant - Gas Turb	0	0	0	0
	Other Generation Maintenance	**0**	-	-	**0**
5680000	Maint Supv & Engineering	50,456	25	3	50,427
5690000	Maintenance of Structures	4,218	0	0	4,218
5691000	Maint of Computer Hardware	11,867	31	24	11,812

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Account	Description	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
5692000	Maint of Computer Software	164,103	3,043	0	161,059
5693000	Maint of Communication Equip	9,975	0	0	9,975
5700000	Maint of Station Equipment	431,440	18,210	0	413,230
5710000	Maintenance of Overhead Lines	1,406,568	(1,789)	59	1,408,298
5720000	Maint of Underground Lines	108	0	0	108
5730000	Maint of Misc Trnsmssion Plt	145,153	0	0	145,153
	Transmission Maintenance	**2,223,667**	**19,521**	**87**	**2,204,280**
5900000	Maint Supv & Engineering	1,705	1,696	(1)	10
5910000	Maintenance of Structures	7,323	6,665	0	658
5920000	Maint of Station Equipment	394,683	382,885	36	11,763
5930000	Maintenance of Overhead Lines	18,914,455	18,911,217	2,576	662
5930001	Tree and Brush Control	205,701	205,701	0	0
5930008	Maint Ovh Lines Strm Exp-OvUnd	1,292	1,292	0	0
5930010	Storm Expense Amortization	2,740,759	2,740,759	0	0
5940000	Maint of Underground Lines	51,224	51,224	0	0
5950000	Maint of Line Trnf Rglators&Dvi	37,476	37,476	0	0
5960000	Maint of St/t Lghtng & Sgnal S	35,565	35,565	0	0
5970000	Maintenance of Meters	46,657	44,851	0	1,807
5980000	Maint of Misc Distribution Plt	106,603	106,051	0	551
	Distribution Maintenance	**22,543,443**	**22,525,381**	**2,611**	**15,451**
9350000	Maintenance of General Plant	149	0	0	149
9350001	Maint of Structures - Owned	211,801	209,428	2	2,372
9350002	Maint of Structures - Leased	32,017	30,352	1,078	586
9350003	Maint of Prpty Held Fture Use	451	(1)	454	(1)
9350006	Maint of Carrier Equipment	13	13	0	0
9350012	Maint of Data Equipment	346	0	346	0
9350013	Maint of Cmmncation Eq-Unall	412,482	378,756	33,726	0
9350015	Maint of Office Furniture & Eq	345,626	168,524	177,103	0
9350016	Maintenance of Video Equipment	120	120	0	0
9350019	Maint of Gen Plant-SCADA Equ	269	266	2	0
9350023	Site Communications Services	286	0	286	0
9350024	Maint of DA-AMI Comm Equip	100	100	0	0
	Administration & General Maintenance	**1,003,661**	**787,558**	**212,997**	**3,106**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**41,893,075**	**23,332,620**	**16,337,674**	**2,222,781**
	Total Operational and Maintenance Expenses	**88,073,679**	**62,081,279**	**40,595,925**	**6,156,320**
4040001	Amort. of Plant	2,030,022	895,080	791,535	343,408
4060001	Amort of Pl Acq Adj	22,526	0	0	22,526
	DDA Amortization	**2,052,548**	**895,080**	**791,535**	**365,934**
4073000	Regulatory Debits	168,634	0	0	168,634
	DDA Regulatory Debits	**168,634**	-	-	**168,634**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**2,221,182**	**895,080**	**791,535**	**534,568**
4030001	Depreciation Exp	52,046,451	14,787,058	32,211,556	5,047,837
	DDA Depreciation	**52,046,451**	**14,787,058**	**32,211,556**	**5,047,837**
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	283,744	0	283,744	0
	DDA Asset Retirement Obligation	**283,744**	-	**283,744**	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**52,330,195**	**14,787,058**	**32,495,299**	**5,047,837**
	Depreciation and Amortization	**54,551,377**	**15,682,138**	**33,286,834**	**5,582,405**
	Franchise Taxes	-	-	-	-
408100613	State Gross Receipts Tax	(5,942)	1	(5,943)	0
408100614	State Gross Receipts Tax	35,223	0	35,223	0
	Revenue-kWhr Taxes	**29,281**	**1**	**29,280**	-
4081002	FICA	2,378,309	1,007,891	1,254,194	116,224
4081003	Federal Unemployment Tax	18,327	7,953	9,406	969
4081007	State Unemployment Tax	66,018	25,142	37,660	3,215
4081033	Fringe Benefit Loading - FICA	(745,082)	(457,100)	(226,247)	(61,735)
4081034	Fringe Benefit Loading - FUT	(5,322)	(3,119)	(1,886)	(317)
4081035	Fringe Benefit Loading - SUT	(14,128)	(6,847)	(6,566)	(715)
	Payroll Taxes	**1,698,121**	**573,921**	**1,066,560**	**57,641**
408102014	State Business Occup Taxes	2,317,333	0	2,317,333	0
	Capacity Taxes	**2,317,333**	-	**2,317,333**	-
408100509	Real & Personal Property Taxes	3,975	3,907	0	69
408100510	Real Personal Property Taxes	131	131	0	0
408100512	Real Personal Property Taxes	1,585,555	111,154	1,447,634	26,766
408100513	Real Personal Property Taxes	6,184,802	3,496,059	742,813	1,945,930

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098 V2014-07-31	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
408102910	Real-Pers Prop Tax-Cap Leases	12	12	0	0
408102913	Real Pers Prop Tax-Cap Leases	1,038	790	68	180
408102914	Real-Pers Prop Tax-Cap Leases	13,612	9,464	1,803	2,345
408103613	Real Prop Tax-Cap Leases	(1,473)	(1,473)	0	0
408103614	Real Prop Tax-Cap Leases	14,875	14,875	0	0
408200513	Real Personal Property Taxes	33,019	5,642	0	27,377
	Property Taxes	**7,835,546**	**3,640,560**	**2,192,319**	**2,002,667**
408101813	St Publ Serv Comm Tax-Fees	473,122	473,122	0	0
408101814	St Publ Serv Comm Tax-Fees	89,129	89,129	0	0
	Regulatory Fees	**562,252**	**562,252**	-	-
408101414	Federal Excise Taxes	1,745	0	1,745	0
	Production Taxes	**1,745**	-	**1,745**	-
408101714	St Lic Rgstrion Tax-Fees	200	200	0	0
408101900	State Sales and Use Taxes	(342,470)	(156,655)	(178,775)	(7,040)
408101912	State Sales and Use Taxes	218,039	89,065	119,078	9,896
408101913	State Sales and Use Taxes	1,295	1,295	0	0
408101914	State Sales and Use Taxes	9,662	9,662	0	0
408102214	Municipal License Fees	425	425	0	0
	Miscellaneous Taxes	**(112,849)**	**(56,008)**	**(59,697)**	**2,856**
	Other Non-Income Taxes	**(111,104)**	**(56,008)**	**(57,953)**	**2,856**
	Taxes Other Than Income Taxes	**12,331,428**	**4,720,726**	**5,547,539**	**2,063,164**
	TOTAL OPERATING EXPENSES	**154,956,484**	**82,484,143**	**79,430,298**	**13,801,889**
	Memo: SEC Total Operating Expenses	**408,748,387**	**345,082,434**	**333,222,169**	**13,801,913**
	OPERATING INCOME	**100,836,389**	**16,181,695**	**40,899,577**	**43,955,118**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	24,537	10,836	11,263	2,438
	Interest & Dividend NonAffiliated	**24,537**	**10,836**	**11,263**	**2,438**
4190001	Interest Inc - Assoc Non CBP	14,193	14,193	0	0
4190005	Interest Income - Assoc CBP	25,851	1,322	(38,676)	63,205
	Interest & Dividend Affiliated	**40,044**	**15,515**	**(38,676)**	**63,205**
	Total Interest & Dividend Income	**64,581**	**26,351**	**(27,413)**	**65,642**
4210039	Carrying Charges	36,552	0	0	36,552
	Interest & Dividend Carrying Charge	**36,552**	-	-	**36,552**
	Memo: Total Interest & Dividend Income w/ Carrying	**101,133**	**26,351**	**(27,413)**	**102,194**
4191000	Allw Oth Fnds Usd Dring Cnstr	2,948,981	247,558	1,818,506	882,917
	AFUDC	**2,948,981**	**247,558**	**1,818,506**	**882,917**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
4270002	Int on LTD - Install Pur Contr	4,114	4,114	0	0
	Interest LTD IPC	**4,114**	**4,114**	-	-
4300001	Interest Exp - Assoc Non-CBP	812,500	235,708	193,074	183,718
	Interest LTD Notes Payable - Affiliated	**612,500**	**235,708**	**193,074**	**183,718**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	19,832,579	7,632,171	6,251,682	5,948,725
	Interest LTD Senior Unsecured	**19,832,579**	**7,632,171**	**6,251,682**	**5,948,725**
4270012	PCRB Interest Exp-Assoc	14,193	14,193	0	0
	Interest LTD Other - Affil	**14,193**	**14,193**	-	-
4270005	Int on LTD - Other LTD	1,694,444	1,701,042	(6,597)	0
	Interest LTD Other - NonAffil	**1,694,444**	**1,701,042**	**(6,597)**	-
	Interest on Long-Term Debt	**22,157,830**	**9,587,228**	**6,438,159**	**6,132,443**
4300003	Int to Assoc Co - CBP	28,026	4,289	169,411	(145,673)
	Interest STD - Affil	**28,028**	**4,289**	**169,411**	**(145,673)**
4310007	Lines Of Credit	482,902	183,355	235,846	43,701
	Interest STD - NonAffil	**462,902**	**183,355**	**235,846**	**43,701**
	Interest on Short Term Debt	**490,929**	**187,644**	**405,257**	**(101,972)**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	1,708	0	1,708	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	274,859	105,774	86,642	82,443
	Amort of Debt Disc, Prem & Exp	**276,567**	**105,774**	**88,350**	**82,443**
4281004	Amrtz Loss Rcqured Debt-Dbnt	19,628	7,554	6,187	5,887
	Amort Loss on Reacquired Debt	**19,628**	**7,554**	**6,187**	**5,887**
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	69,368	20,568	41,514	7,287
4310002	Interest on Customer Deposits	16,516	16,516	0	0
4310023	Interest Expense - State Tax	2,203	1,098	1,052	53

American Electric Power

INCOME STATEMENT

GLS8016
YTD Jul 2014
08/08/2014 15:18

Layout: GLS8016

09B V2014-07-31	Account: GL_ACCT_SEC Business Units: SEGMENT_COMB	Kentucky Power Int Consol GLS8016 Actual YTD Jul 2014	Kentucky Power Company - Distribution 110 Actual YTD Jul 2014	Kentucky Power Company - Generation 117 Actual YTD Jul 2014	Kentucky Power Company - Transmission 180 Actual YTD Jul 2014
	Other Interest - NonAffil	88,088	38,182	42,566	7,340
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(1,495,174)	(122,507)	(932,243)	(440,424)
	AFUDC-Borrowed Funds	(1,495,174)	(122,507)	(932,243)	(440,424)
	Total Interest Charges	21,537,867	9,803,875	6,048,276	5,685,717
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	82,348,635	6,651,729	36,442,395	39,254,512
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	28,125,101	3,786,344	13,250,086	11,088,671
4092001	Inc Tax, Oth Inc&Ded-Federal	(423,474)	(262,310)	(129,959)	(31,206)
	Federal Current Income Tax	27,701,627	3,524,034	13,120,127	11,057,465
4101001	Prov Def I/T Util Op Inc-Fed	26,734,608	2,855,966	21,667,003	2,211,639
4102001	Prov Def I/T Oth I&D - Federal	434,435	218,898	174,596	40,942
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(29,139,521)	(4,363,771)	(23,920,662)	(855,088)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(40,885)	0	(40,885)	0
	Federal Deferred Income Tax	(2,011,363)	(1,288,907)	(2,119,948)	1,397,493
4114001	ITC Adj, Utility Oper - Fed	(56,022)	(8,820)	(13,482)	(33,720)
	Federal Investment Tax Credits	(56,022)	(8,820)	(13,482)	(33,720)
	Federal Income Taxes	25,634,242	2,226,307	10,986,697	12,421,237
409100214	Income Taxes UOI - State	4,886,173	249,764	2,708,631	1,927,778
409200214	Inc Tax Oth Inc Ded - State	(73,502)	(45,529)	(22,557)	(5,416)
	State Current Income Tax	4,812,670	204,235	2,686,074	1,922,362
4111002	Prv Def I/T-Cr UtilOpInc-State	(356,720)	0	(356,720)	0
	State Deferred Income Tax	(356,720)	-	(356,720)	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	4,455,950	204,235	2,329,354	1,922,362
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	30,090,192	2,430,542	13,316,051	14,343,599
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	52,258,443	4,221,187	23,126,344	24,910,913
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	52,258,443	4,221,187	23,126,344	24,910,913
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	52,258,443	4,221,187	23,126,344	24,910,913
	NET INCOME (LOSS) NODE before PS	52,258,443	4,221,187	23,126,344	24,910,913
	Double Check on Net Income Node after PS	(0)	0	0	-

Reserved Section

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Jul 2014
08/11/2014 13:25

Layout : GLS8216

09B V2014-07- Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Jul 2014	YTD Jul 2014	YTD Jul 2014	YTD Jul 2014
ASSETS				
Cash and Cash Equivalents	557,882	557,882	0	0
Other Cash Deposits	0	0	0	0
Customers	22,266,184	9,926,239	10,016,714	2,323,232
Accrued Unbilled Revenues	(9,290,374)	(9,681,440)	391,067	0
Miscellaneous Accounts Receivable	29,085,775	7,701,203	71,692,390	11,421,002
Allowances for Uncollectible Accounts	(28,541)	(16,914)	(11,628)	0
Accounts Receivable	42,033,044	7,929,088	82,088,543	13,744,233
Advances to Affiliates	72,514,272	(13,307,942)	(29,776,818)	115,599,032
Fuel, Materials and Supplies	59,756,909	2,339,939	56,506,229	910,740
Risk Management Contracts - Current	4,307,253	4,805	4,302,448	0
Margin Deposits	2,009,740	19,123	1,990,617	0
Unrecovered Fuel - Current	10,501,806	0	10,501,806	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	3,799,019	2,870,117	742,848	186,053
TOTAL CURRENT ASSETS	195,479,924	413,013	126,355,673	130,440,058
Electric Production	1,147,857,440	758,874,796	1,611,733,157	510,219,792
Electric Transmission	513,528,045	0	0	0
Electric Distribution	713,356,635	0	0	0
General Property, Plant and Equipment	511,615,061	199,571	4,169,386	1,160,479
Construction Work-In-Progress	79,319,866	9,397,775	27,839,432	42,082,659
TOTAL PROPERTY, PLANT and EQUIPMENT	2,965,677,047	768,472,142	1,643,741,975	553,462,929
less: Accumulated Depreciation and Amortization	(988,964,024)	(242,852,000)	(575,226,381)	(170,885,643)
NET PROPERTY, PLANT and EQUIPMENT	1,976,713,023	525,620,142	1,068,515,594	382,577,286
Net Regulatory Assets	214,021,082	101,745,239	56,590,930	55,684,913
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	2,010,682	0	2,010,682	0
Employee Benefits and Pension Assets	15,721,807	45,777	15,228,674	447,356
Other Non Current Assets	9,851,947	3,781,043	4,178,946	1,891,958
TOTAL OTHER NON-CURRENT ASSETS	241,605,517	105,572,059	78,009,231	58,024,227
TOTAL ASSETS	2,413,798,465	631,605,214	1,272,880,499	571,041,571
LIABILITIES				
Accounts Payable	81,784,605	65,218,869	73,308,877	4,985,679
Advances from Affiliates	0	0	0	0
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	265,000,000	0	265,000,000	0
Long-Term Debt Due Within One Year - Affiliated	20,000,000	7,063,600	7,356,600	5,579,800
Risk Management Liabilities	521,599	779	520,820	0
Accrued Taxes	34,465,804	8,153,332	8,052,383	18,260,089
Memo: Property Taxes	12,193,486	6,140,917	2,267,343	3,785,226
Accrued Interest	9,528,920	3,372,270	3,516,253	2,640,397
Risk Management Collateral	307,188	0	307,188	0
Utility Customer Deposits	24,890,779	24,890,779	0	0
Deposits - Customer and Collateral	25,197,968	24,890,779	307,188	0
Over-Recovered Fuel Costs - Current	0	0	0	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,149,142	500,002	505,752	143,388
Tax Collections Payable	2,187,996	2,091,087	90,742	6,166
Revenue Refunds - Accrued	1,156,158	0	36,562	1,119,596
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	1,580,310	611,860	888,972	79,479
Accrued Rents	1,207	1,207	0	0

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216
YTD Jul 2014
08/11/2014 13:25

Layout : GLS8216

09B V2014-07- Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS		Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
		YTD Jul 2014	YTD Jul 2014	YTD Jul 2014	YTD Jul 2014
	Accrued ICP	4,620,777	1,790,625	2,654,891	175,261
	Accrued Vacations	5,171,837	2,035,786	2,879,828	256,223
	Misc Employee Benefits	1,327,052	488,094	833,872	5,087
	Payroll Deductions	203,089	89,147	102,001	11,941
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	695,623	279,632	395,483	20,508
2530022	Customer Advance Receipts	1,314,527	1,314,527	0	0
	Customer Advance	1,314,527	1,314,527	0	0
2420511	Control Cash Disburse Account	3,967,125	3,967,125	0	0
	Control Cash Disbursement Account	3,967,125	3,967,125	0	0
	JMG Liability	0	0	0	0
2420088	Econ. Development Fund Curr	116,500	0	116,500	0
2420506	Est Financing Cost - Bonds	(119,391)	0	(119,391)	0
2420512	Unclaimed Funds	70,217	70,217	0	0
2420542	Acc Cash Franchise Req	64,503	64,503	0	0
242059214	Sales Use Tax - Lease Equip	82	0	43	39
2420643	Accrued Audit Fees	50,207	10,561	33,023	6,623
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	246,141	0	246,141	0
2530050	Deferred Rev -Pole Attachments	52,815	52,815	0	0
2530112	Other Deferred Credits-Curr	221,616	0	221,616	0
2530124	Contr In Aid of Constr Advance	27,942	27,942	0	0
2530177	Deferred Rev-Bonus Lease Curr	431,564	0	431,564	0
	Misc Current and Accrued Liabilities	1,716,522	226,038	1,483,822	6,663
	Current Other and Accrued Liabilities	23,942,222	12,895,127	9,366,173	1,680,922
	Other Current Liabilities	**25,091,364**	**13,395,128**	**9,871,925**	**1,824,310**
	TOTAL CURRENT LIABILITIES	**461,590,259**	**122,094,757**	**367,934,046**	**33,290,275**
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**530,000,000**	**187,185,400**	**194,949,900**	**147,864,700**
	Long-Term Debt - Premiums and Discounts Unamort	(514,069)	(181,559)	(189,090)	(143,420)
	Memo - LTD NonAffiliated and Premiums	*529,485,931*	*187,003,841*	*194,760,810*	*147,721,280*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	1,133,051	3,433	1,129,618	0
	Long-Term Risk Management Liabilities - MTM	1,133,051	3,433	1,129,618	0
	Long-Term Risk Management Liabilities	**1,133,051**	**3,433**	**1,129,618**	**0**
	Deferred Income Taxes	**553,171,814**	**168,263,239**	**265,438,519**	**119,470,056**
	Deferred Investment Tax Credits	**69,725**	**15,345**	**24,346**	**30,035**
	Regulatory Liabilities and Deferred Credits	**25,165,336**	(32,345,866)	**63,905,399**	(6,394,197)
	Memo - Reg Liab and Def ITC	*25,235,062*	*(32,330,521)*	*63,929,745*	*(6,364,162)*
	Asset Retirement Obligation	**63,569,918**	**63,018**	**63,506,900**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,824,534**	**3,057,857**	**4,669,498**	**97,179**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Red	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	3,539,410	1,370,302	1,719,063	450,045
	Def Credits - Income Tax	683,714	362,465	278,593	42,656
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	115,727	115,727	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	4,673	0	4,673	0
2530067	IPP - System Upgrade Credits	273,958	0	0	273,958
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	153,162	153,162	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	95,266	0	0	95,266
2530178	Deferred Rev-Bonus Lease NC	1,618,365	0	1,618,365	0
	Def Credits - Other	2,145,424	153,162	1,623,038	369,224
	Total Other Deferred Credits	2,261,151	268,889	1,623,038	369,224
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	815,500	0	815,500	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Jul 2014
08/11/2014 13:25

Layout : GLS8216

09B V2014-07- Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	Kentucky Power Int Consol GLS8216 YTD Jul 2014	Kentucky Power Company - 110 YTD Jul 2014	Kentucky Power Company - Generation 117 YTD Jul 2014	Kentucky Power Company - 180 YTD Jul 2014
Other Non-Current Liabilities	8,410,418	2,001,656	5,546,837	861,925
TOTAL NON-CURRENT LIABILITIES	1,188,830,729	328,062,523	598,981,928	261,786,278
TOTAL LIABILITIES	1,650,420,988	450,157,280	966,915,974	295,076,553
Cumulative Pref Stocks of Subs - Not subject Mand Rede	0	0	0	0
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS' EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	517,459,453	106,025,371	327,394,246	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	201,949,367	53,084,311	(25,353,754)	174,218,810
Accumulated Other Comprehensive Income (Loss)	(6,481,344)	(65,798)	(6,363,570)	(51,976)
TOTAL SHAREHOLDERS' EQUITY	763,377,477	181,447,934	305,964,524	275,965,018
Memo: Total Equity	763,377,477	181,447,934	305,964,524	275,965,018
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	2,413,798,465	631,605,214	1,272,880,499	571,041,571
out-of-balance	(0)	0	0	(0)

Reserved Section

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Kentucky Power Corp Consol
Comparative Balance Sheet
July 31, 2013

Run Date: 08/09/2013 13:17

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V
KYP_CORP_C(V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS

	Month End Balances 2013	December Balances Last Year	Variance $
ASSETS			
PRODUCTION	560,353,613.06	558,934,668.00	1,418,945.06
TRANSMISSION	491,204,759.66	490,152,082.00	1,052,677.66
DISTRIBUTION	672,713,158.90	652,615,328.83	20,097,830.07
GENERAL	60,916,643.83	57,451,300.18	3,465,343.65
CONSTRUCTION WORK IN PROGRESS	51,735,106.99	44,281,291.91	7,453,815.08
ELECTRIC UTILITY PLANT	**1,836,923,282.44**	**1,803,434,670.92**	**33,488,611.52**
less Accum Provision - Depre, Depl, Amort.	(646,444,574.92)	(624,238,902.51)	(22,205,672.41)
NET ELECTRIC UTILITY PLANT	**1,190,478,707.52**	**1,179,195,768.41**	**11,282,939.11**
Net NonUtility Property	2,654,986.88	5,498,717.60	(2,843,730.72)
Investment in Subsidiary & Associated	0.00	0.00	0.00
Other Investments	257,415.67	260,727.67	(3,312.00)
Other Special Funds	0.00	0.00	0.00
Allowance - NonCurrent	2,361,233.00	2,361,232.37	0.63
Long Term Energy Trading Contracts	4,881,000.29	6,881,654.77	(2,000,654.48)
OTHER PROPERTY AND INVESTMENTS	**10,154,635.84**	**15,002,332.41**	**(4,847,696.57)**
Cash and Cash Equivalents	1,449,717.79	1,925,747.09	(476,029.30)
Advances to Affiliates	19,927,105.24	0.00	19,927,105.24
Acct Rec - Customers	14,239,196.44	12,676,052.64	1,563,143.81
Acct Rec - Miscellaneous	1,521,502.98	3,141,697.43	(1,620,194.45)
Acct Rec - AP for Uncollectible Accounts	(18,278.76)	(141,538.08)	123,259.32
Acct Rec - Associated Companies	60,505,832.83	9,241,088.58	51,264,744.25
Fuel Stock	50,663,910.98	69,147,176.47	(18,483,265.49)
Materials and Supplies	21,057,551.59	25,061,279.42	(4,003,727.83)
Accrued Utility Revenues	(5,838,863.21)	816,939.53	(6,655,802.74)
Energy Trading	6,225,310.09	6,174,819.72	50,490.37
Prepayments	2,427,973.62	1,569,794.80	858,178.82
Other Current Assets	1,330,336.89	1,660,942.94	(330,606.05)
CURRENT ASSETS	**173,491,296.47**	**131,274,000.53**	**42,217,295.95**
REGULATORY ASSETS	**213,009,841.46**	**214,900,829.18**	**(1,890,987.72)**
TOTAL DEFERRED CHARGES	**68,730,099.11**	**78,498,798.33**	**(9,768,699.22)**
TOTAL ASSETS	**1,655,864,580.40**	**1,618,871,728.86**	**36,992,851.54**
CAPITALIZATION and LIABILITIES			
COMMON STOCK			
Authorized: 2,000,000 Shares			
Outstanding: 1,009,000 Shares			
Common Stock	50,450,000.00	50,450,000.00	0.00
Premium on Capital Stock	0.00	0.00	0.00
Paid-In-Capital	238,552,728.41	238,341,119.49	211,608.92
Retained Earnings	204,611,735.34	190,818,915.56	13,792,819.78
COMMON SHAREHOLDERS' EQUITY	**493,614,463.75**	**479,610,035.05**	**14,004,428.69**
PS Subject To Mandatory Redemption	0.00	0.00	0.00
PS Not Subject Mandatory Redemption	0.00	0.00	0.00

Kentucky Power Corp Consol
Comparative Balance Sheet
July 31, 2013

Run Date: 08/09/2013 13:17

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V
KYP_CORP_CI V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS

		Month End Balances 2013	December Balances Last Year	Variance $
	CUMULATIVE PREFERRED STOCK	**0.00**	**0.00**	**0.00**
	TRUST PREFERRED SECURITIES	**0.00**	**0.00**	**0.00**
	Long-Term Debt Less Amt Due 1 Yr	**549,319,206.25**	**549,221,950.00**	**97,256.25**
	CAPITALIZATION	**1,042,933,670.00**	**1,028,831,985.05**	**14,101,684.95**
	Obligations Under Capital Lease-NonCurrent	1,948,068.32	1,674,300.89	273,767.43
	Accumulated Provision Rate Relief	0.00	1,635,430.00	(1,635,430.00)
	Accumlated Provision - Miscellanous	35,709,993.88	34,033,794.12	1,676,199.76
	Other NonCurrent Liabilities	**37,658,062.20**	**37,343,525.01**	**314,537.19**
	Preferred Stock Due Within 1 Year	0.00	0.00	0.00
	Long-Term Debt Due Within 1 Year	0.00	0.00	0.00
	Accumulated Provision Due Within 1 Year	0.00	0.00	0.00
	Short-Term Debt	0.00	0.00	0.00
	Advances from Affiliates	0.00	13,358,855.63	(13,358,855.63)
	A/P General	20,837,973.83	30,336,776.64	(9,498,802.81)
	A/P Associated Companies	85,413,873.87	41,052,680.18	44,361,193.68
	Customer Deposits	24,554,945.42	23,484,964.81	1,069,980.61
	Taxes Accrued	5,731,408.79	6,548,714.64	(817,305.85)
	Interest Accrued	9,206,898.51	7,166,695.02	2,040,203.49
	Dividends Accrued	0.00	0.00	0.00
	Obligation Under Capital Leases	1,246,137.64	1,403,875.95	(157,738.31)
	Energy Contracts Current	3,087,695.60	3,320,068.02	(232,372.42)
	Other Current and Accrued Liabilities	16,073,561.96	17,797,808.10	(1,724,246.14)
	Current Liabilities	**166,152,495.61**	**144,470,438.99**	**21,682,056.62**
	Deferred Income Taxes	**391,522,277.17**	**385,153,166.17**	**6,369,111.00**
	Deferred Investment Tax Credits	**221,586.88**	**355,758.82**	**(134,171.94)**
	Regulatory Liabilities	**11,200,123.03**	**13,831,965.72**	**(2,631,842.69)**
2440002	LT Unreal Losses - Non Affil	3,205,154.43	4,200,196.07	(995,041.64)
2440022	L/T Liability MTM Collateral	(266,827.00)	(582,545.00)	315,718.00
2450011	L/T Liability-Commodity Hedges	1,540.00	82,731.00	(81,191.00)
	Long-Term Energy Trading Contracts	2,939,867.43	3,700,382.07	(760,514.64)
2520000	Customer Adv for Construction	56,251.53	63,177.74	(6,926.21)
	Customer Advances for Construction	56,251.53	63,177.74	(6,926.21)
	Deferred Gains on Sale/Leaseback	0.00	0.00	0.00
	Deferred Gains on Dispostion of Utility Plant	0.00	0.00	0.00
2530000	Other Deferred Credits	0.00	0.00	0.00
2530022	Customer Advance Receipts	1,583,777.81	2,634,497.53	(1,050,719.72)
2530050	Deferred Rev -Pole Attachments	86,555.17	78,940.35	7,614.82
2530067	IPP - System Upgrade Credits	265,231.99	260,279.72	4,952.27
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	159,302.00	162,614.00	(3,312.00)
2530112	Other Deferred Credits-Curr	221,616.17	1,113,326.72	(891,710.55)
2530114	Federl Mitigation Deferal(NSR)	754,941.55	754,941.55	0.00

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Kentucky Power Corp Consol
Comparative Balance Sheet
July 31, 2013

Run Date: 08/09/2013 13:17

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V KYP_CORP_C(V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS		Month End Balances 2013	December Balances Last Year	Variance $
2530137	Fbr Opt Lns-Sold-Defd Rev	108,821.87	116,729.42	(7,907.55)
	Other Deferred Credits	3,180,246.56	5,121,329.29	(1,941,082.73)
	Deferred Credits	**6,176,365.52**	**8,884,889.10**	**(2,708,523.58)**
	DEFERRED CREDITS & REGULATED LIABILITIES	**409,120,352.60**	**408,225,779.81**	894,572.79
	CAPITAL & LIABILITIES	**1,655,864,580.41**	**1,618,871,728.87**	36,992,851.55

Statement of Retained Earnings

	BALANCE AT BEGINNING OF YEAR	**190,818,915.56**	**171,840,462.36**	18,978,453.21
	Net Income (Loss)	26,292,819.77	50,978,453.21	(24,685,633.43)
	Deductions:			
	Dividend Declared On Common Stock	(12,500,000.00)	-32,000,000	19,500,000.00
	Dividend Declared On Preferred Stock	0.00	0	0.00
	Adjustment in Retained Earnings	0.00	0.00	0.00
	Total Deductions	**(12,500,000.00)**	**(32,000,000.00)**	19,500,000.00
	BALANCE AT END OF PERIOD (A)	**204,611,735.34**	**190,818,915.56**	13,792,819.78

(A) Represents The Following Balances At End Of Period

215.0	Appropriated Retained Earnings	0.00	0.00	0.00
215.1	Appr Retnd Erngs - Amrt Rsv, Fed	0.00	0.00	0.00
	Total Appropriated Retained Earnings	0.00	0.00	0.00
2160000-1	Unapprp Retained Earnings Unrestr	190,818,915.56	171,840,462.36	18,978,453.21
2160002+	Unapprp Retained Earnings Restr	0.00	0.00	0.00
210.0	Gain on Reacquired Pref Stock	0.00	0.00	0.00
	Net Income Transferred	13,792,819.78	18,978,453.21	(5,185,633.43)
	Total Unappropriated Retained Earnings	204,611,735.34	190,818,915.56	13,792,819.78
216.1	Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
418.1	Equity Earnings of Subsidiary Co	0.00	0.00	0.00
	Total Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
	Total Other Retained Earnings Accounts	0.00	0.00	(0.00)
	TOTAL RETAINED EARNINGS	**204,611,735.34**	**190,818,915.56**	13,792,819.78

Final 08/12/2014

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - July, 2014

GLR7210V 08/12/14 07:12

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	125,539,704.96	(2,426,401.52)	(9.12)	0.00	1,601,797,546.20
	TOTAL PRODUCTION	1,478,684,251.88	125,539,704.96	(2,426,401.52)	(9.12)	0.00	1,601,797,546.20
101/106	TRANSMISSION	503,165,571.80	6,410,378.07	(160,573.08)	0.00	0.00	509,415,376.79
101/106	DISTRIBUTION	733,776,590.81	26,327,005.15	(4,566,935.62)	0.00	0.00	755,536,660.34
	TOTAL (ACCOUNTS 101 & 106)	2,715,626,414.49	158,277,088.18	(7,153,910.22)	(9.12)	0.00	2,866,749,583.33
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	393,053.48	0.00	6,672,202.65
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	2,721,905,563.66	158,277,088.18	(7,153,910.22)	393,044.36	0.00	2,873,421,785.98
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	CONSTRUCTION WORK IN PROGRESS:						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		66,419,993.55				
107000X	TRANSFERS		(115,699,275.55)				
107000X	END. BAL.		(49,279,282.00)				79,319,866.19
	TOTAL ELECTRIC UTILITY PLANT	2,857,910,670.58	108,997,806.18	(7,153,910.22)	393,044.36	0.00	2,960,147,610.90
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	5,529,435.74	0.00	0.00	(0.03)	0.00	5,529,435.71

Acct 107 Transfers	(115,699,275.55)
Acct 101/6 Additions	158,277,088.18
	42,577,812.63
ARO - ASH#1 Big Sandy Ash Pond 07/2014	42,577,812.63

Prepared by: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - July, 2014

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	32,832,389.68	(2,426,401.52)	(1,644,395.34)	0.00	628,265,719.71
1080001/11	TRANSMISSION	161,537,795.16	5,047,836.98	(160,573.08)	(240,721.33)	0.00	166,184,337.73
1080001/11	DISTRIBUTION	192,744,660.64	14,790,343.84	(4,566,935.62)	(1,081,660.89)	0.00	201,886,407.97
1080013	PRODUCTION	(3,620,015.26)	0.00	0.00	0.00	(305,544.24)	(3,925,559.50)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698.85)	0.00	0.00	0.00	(5,359.29)	(32,058.14)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(3,664,858.72)	2,966,777.56	(9,018,333.68)
	TOTAL (108X accounts)	**941,819,616.07**	**52,670,570.50**	**(7,153,910.22)**	**(6,631,636.28)**	**2,655,874.03**	**983,360,514.10**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	791,534.74	0.00	0.00	84,795.27	11,305,680.88
1110001	TRANSMISSION	1,607,792.68	343,407.70	0.00	0.00	0.00	1,951,200.38
1110001	DISTRIBUTION	7,182,584.75	895,079.62	0.00	0.00	0.00	8,077,664.37
	TOTAL (111X accounts)	**19,219,728.30**	**2,030,022.06**	**0.00**	**0.00**	**84,795.27**	**21,334,545.63**
1011006	CAPITAL LEASES	1,869,467.09	0.00	0.00	0.00	114,184.19	1,983,651.28
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**962,908,811.46**	**54,700,592.56**	**(7,153,910.22)**	**(6,631,636.28)**	**2,854,853.49**	**1,006,678,711.01**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonutl Prop-Ownd	214,955.75	3,890.67	0.00	0.00	0.00	218,846.42
1240027	Other Property - RWIP	(3,400.00)	0.00	0.00	0.00	0.00	(3,400.00)
	TOTAL NONUTILITY PLANT	**211,555.75**	**3,890.67**	**0.00**	**0.00**	**0.00**	**215,446.42**

Prepared by: PSnVision Report GLR7410V
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of info: Powerplant Reports and PS GL

AEP
AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215 2373
AEP.com

September 24, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed August 2014 Financial Report pages for Kentucky Power Company consisting of the following:

Sincerely,

Brian J Frantz

Brian J. Frantz
Manager –Regulated Accounting

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American Electric Power

INCOME STATEMENT

GLS8016
YTD Aug 2014
09/09/2014 15:55

Layout: GLS8016

098 V2014-08-31		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Aug 2014	Kentucky Power Company - Distribution 110 Actual YTD Aug 2014	Kentucky Power Company - Generation 117 Actual YTD Aug 2014	Kentucky Power Company - Transmission 180 Actual YTD Aug 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	81,828,184	81,449,543	378,641	0
4400002		Residential Sales-W/O Space Ht	37,073,099	36,832,745	240,355	0
4400005		Residential Fuel Rev	52,066,435	52,066,435	0	0
	A	**Revenue - Residential Sales**	**170,967,718**	**170,348,722**	**618,996**	-
4420001		Commercial Sales	51,804,142	51,760,873	43,269	0
4420006		Sales to Pub Auth - Schools	9,229,333	9,142,422	86,911	0
4420007		Sales to Pub Auth - Ex Schools	9,667,563	9,645,679	21,884	0
4420013		Commercial Fuel Rev	30,145,677	30,145,677	0	0
	A	**Revenue - Commercial Sales**	**100,846,715**	**100,694,651**	**152,064**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	43,019,433	42,819,221	200,212	0
4420004		Ind Sales-NonAffil(Incl Mines)	19,928,243	19,775,701	152,543	0
4420016		Industrial Fuel Rev	62,524,228	62,524,228	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**125,471,904**	**125,119,149**	**352,755**	-
		Revenue - Industrial Sales	**125,471,904**	**125,119,149**	**352,755**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	987,390	979,086	8,303	0
4440002		Public St & Hwy Light Fuel Rev	212,522	212,522	0	0
	A	**Revenue - Other Retail Sales**	**1,199,912**	**1,191,609**	**8,303**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**398,486,249**	**397,354,131**	**1,132,118**	-
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	23,142,332
4561033		PJM NITS Revenue - Affiliated	12,945,597	0	0	25,118,722
4561034		PJM TO Adm. Serv Rev - Aff	0	0	0	417,516
4561035		PJM Affiliated Trans NITS Cost	(12,436,087)	0	(24,609,212)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(417,516)	0
4561059		Affil PJM Trans Enhancmnt Rev	208,415	0	0	316,634
4561060		Affil PJM Trans Enhancmnt Cost	(197,463)	0	(305,682)	0
4561062		PROVISION RTO Cost - Affi	(1,423,045)	0	(1,423,045)	0
4561063		PROVISION RTO Rev Affiliated	2,192,597	0	0	2,192,597
	B	**Revenue - Transmission-Affiliated**	**1,290,014**	-	**(26,755,455)**	**51,187,800**
4470150		Transm Rev -Dedic Whls/Muni	8,790	0	(502,887)	511,677
4470206		PJM Trans loss credits-OSS	1,611,116	0	1,611,116	0
4470207		PJM transm loss charges - LSE	(12,865,657)	0	(12,865,657)	0
4470208		PJM Transm loss credits-LSE	1,915,482	0	1,915,482	0
4470209		PJM transm loss charges-OSS	(13,085,418)	0	(13,085,418)	0
4561002		RTO Formation Cost Recovery	2,684	0	(94,800)	97,484
4561003		PJM Expansion Cost Recov	54,077	0	(58,543)	112,620
4561005		PJM Point to Point Trans Svc	465,375	0	465,375	0
4561006		PJM Trans Owner Admin Rev	198,224	0	0	198,224
4561007		PJM Network Integ Trans Svc	10,152,185	0	0	10,152,185
4561019		Oth Elec Rev Trans Non Affil	39,513	0	0	39,513
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	4,351	0	0	4,351
4561029		PJM NITS Revenue Whsl Cus-NAff	1,873,760	0	0	1,873,760
4561030		PJM TO Serv Rev Whls Cus-NAff	30,404	0	0	30,404
4561058		NonAffil PJM Trans Enhncmt Rev	316,067	0	0	316,067
4561061		NAff PJM RTEP Rev for Whsl-FR	23,663	0	0	23,663
4561064		PROVISION RTO Rev WhslCus-NAf	167,226	0	0	167,226
4561065		PROVISION RTO Rev - NonAff	977,041	0	0	977,041
	A	**Revenue - Transmission-NonAffiliated**	**(8,111,117)**	-	**(22,615,333)**	**14,504,216**
		Revenue - Transmission	**(6,821,103)**	-	**(49,370,787)**	**65,692,016**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	262	0	262	0
4470128		Sales for Res-Aff. Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,479,520**	-	**5,479,520**	-
4470002		Sales for Resale - NonAssoc	3,131	0	3,131	0
4470006		Sales for Resale-Bookout Sales	11,725,197	0	11,725,197	0
4470010		Sales for Resale-Bookout Purch	(11,770,693)	0	(11,770,693)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	1,916,111	0	1,916,111	0
4470028		Sale/Resale - NA - Fuel Rev	151,564	0	151,564	0
4470033		Whsal/Muni/Pub Auth Base Rev	3,059,977	0	3,059,977	0
4470066		PWR Trding Trans Exp-NonAssoc	(84)	0	(84)	0
4470081		Financial Spark Gas - Realized	35,102	0	35,102	0
4470082		Financial Electric Realized	1,914,715	0	1,914,715	0
4470089		PJM Energy Sales Margin	105,111,174	0	105,111,174	0
4470093		PJM Implicit Congestion-LSE	(18,095,704)	0	(18,095,704)	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Aug 2014
09/09/2014 15:55

Layout: GLS8016

098 V2014-08-31		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Aug 2014	Kentucky Power Company - Distribution 110 Actual YTD Aug 2014	Kentucky Power Company - Generation 117 Actual YTD Aug 2014	Kentucky Power Company - Transmission 180 Actual YTD Aug 2014
4470098		PJM Oper Reserve Rev-OSS	(2,906,342)	0	(2,906,342)	0
4470099		Capacity Cr Net Sales	375,746	0	375,746	0
4470100		PJM FTR Revenue-OSS	622,050	0	622,050	0
4470101		PJM FTR Revenue-LSE	8,481,926	0	8,481,926	0
4470103		PJM Energy Sales Cost	128,775,443	0	128,775,443	0
4470106		PJM Pt2Pt Trans Purch-NonAff	(27)	0	(27)	0
4470107		PJM NITS Purch-NonAff	15,119	0	15,119	0
4470109		PJM FTR Revenue-Spec	(56,290)	0	(56,290)	0
4470110		PJM TO Admin. Exp.-NonAff	35,467	0	35,467	0
4470112		Non-Trading Bookout Sales-OSS	4,943	0	4,943	0
4470115		PJM Meter Corrections-OSS	(17,359)	0	(17,359)	0
4470116		PJM Meter Corrections-LSE	23,967	0	23,967	0
4470124		PJM Incremental Spot-OSS	1	0	1	0
4470126		PJM Incremental Imp Cong-OSS	(26,841,817)	0	(26,841,817)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	2,169,533	0	2,169,533	0
4470144		Realiz Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim Margin Reclass	(175)	0	(175)	0
4470168		Interest Rate Swaps-Power	(10,998)	0	(10,998)	0
4470170		Non-ECR Auction Sales-OSS	1,385,701	0	1,385,701	0
4470174		PJM Whlse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	260,979	0	260,979	0
4470176		OSS Sharing Reclass-Reduction	(260,979)	0	(260,979)	0
4470180		Trading intra-book Reclass	(119,770)	0	(119,770)	0
4470181		Auction intra-book Reclass	119,770	0	119,770	0
4470202		PJM OpRes-LSE-Credit	637,665	0	637,665	0
4470203		PJM OpRes-LSE-Charge	(4,722,555)	0	(4,696,197)	(26,358)
4470204		PJM Spinning-Credit	(0)	0	(0)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,200	0	28,200	0
4470220		PJM Regulation - OSS	132,995	0	132,995	0
4470221		PJM Spinning Reserve - OSS	10,096	0	10,096	0
4470222		PJM Reactive - OSS	411,699	0	411,699	0
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	(10,423)	0	(10,423)	0
5550080		PJM Hourly Net Purch -FERC	(27,165,929)	0	(27,165,929)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**175,430,741**	**-**	**175,457,099**	**(26,358)**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**180,910,261**	**-**	**180,936,619**	**(26,358)**
4470074		Sale for Resale-Aff-Trnf Price	0	0	297,290,976	0
4540001		Rent From Elect Property - Af	173,832	518,254	0	0
4560001		Oth Elect Rev - Affiliated	22,774	0	22,774	0
	B	**Revenue - Other Ele-Affiliated**	**196,606**	**518,254**	**297,313,750**	**-**
4500000		Forfeited Discounts	2,624,690	2,624,690	0	0
4510001		Misc Service Rev - Nonaffil	260,502	251,464	0	9,037
4540002		Rent From Elect Property-NAC	63,189	1,650	57,489	4,050
4540005		Rent from Elec Prop-Pole Attch	3,094,798	3,094,798	0	0
4560007		Oth Elect Rev - DSM Program	3,600,567	3,600,567	0	0
		Revenue - Other Ele-NonAffiliated	**9,643,746**	**9,573,169**	**57,489**	**13,087**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	383	0	383	0
4118004		Comp. Allow. Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,916**	**-**	**8,916**	**-**
	A	**Revenue - Other Ele-NonAffiliated**	**9,652,661**	**9,573,169**	**66,405**	**13,087**
		Revenue - Other Opr Electric	**9,849,267**	**10,091,424**	**297,380,155**	**13,087**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	21,800	21,000	800	0
4180003		Non-Opratng Rntal Inc-Maint	(16)	0	(16)	0
4180005		Non-Opratng Rntal Inc-Depr	(4,446)	0	0	(4,446)
	D	**Non-Operating Rental Income - NonAffiliated**	**17,338**	**21,000**	**784**	**(4,446)**
		Non-Operating Rental Income	**17,338**	**21,000**	**784**	**(4,446)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	1,448	470	585	394

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4210007		Misc Non-Op Inc - NonAsc - Oth	144,555	522	144,033	0
	D	**Non-Operating Misc Income - NonAffiliated**	**146,003**	**992**	**144,618**	**394**
		Non-Operating Misc Income	**146,003**	**992**	**144,618**	**394**
4540004		Rent From Elect Prop-ABD-Nonaf	51,590	51,590	0	0
4560015		Other Electric Revenues - ABD	173,044	153,817	0	19,227
	D	**Associated Business Development Income**	**224,634**	**205,407**	**-**	**19,227**
		Revenue - Other Opr - Other	**387,974**	**227,398**	**145,402**	**15,174**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***387,974***	***227,398***	***145,402***	***15,174***
		Revenue - Other Operating	**10,237,242**	**10,318,822**	**297,525,557**	**28,261**
	A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	-	-	-	-
4210031		Pwr Sales Outside Svc Terrtry	181,875	0	181,875	0
4210032		Pwr Purch Outside Svc Terrtry	(555)	0	(555)	0
	A	**Revenue - Power Sales**	**181,320**	**-**	**181,320**	**-**
		TOTAL OPERATING REVENUES	**582,993,968**	**407,672,953**	**430,404,826**	**65,693,919**
=(A)		*Memo: G/T/D Revenue*	*575,639,854*	*406,927,300*	*154,221,609*	*14,490,945*
=(B)		*Memo: Other Affiliated Revenue*	*6,966,140*	*518,254*	*276,037,815*	*51,187,800*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Non*	*387,974*	*227,398*	*145,402*	*15,174*
		Memo: Total Operating Revenues	***582,993,968***	***407,672,953***	***430,404,826***	***65,693,919***
=(E)=(B)+(C)		***Memo: Affiliated Revenue***	***6,966,140***	***518,254***	***276,037,815***	***51,187,800***
=(F)=(D)+(A)		***Memo: Non-Affiliated Revenue***	***576,027,828***	***407,154,699***	***154,367,011***	***14,506,119***
		Memo: Total Operating Revenues	***582,993,968***	***407,672,953***	***430,404,826***	***65,693,919***
		FUEL EXPENSES				
5010000		Fuel	997,548	14	997,525	9
5010001		Fuel Consumed	195,941,387	0	195,941,387	0
5010003		Fuel - Procure Unload & Handle	8,314,840	0	8,314,840	0
5010012		Ash Sales Proceeds	(21,791)	0	(21,791)	0
5010013		Fuel Survey Activity	(734,602)	0	(734,602)	0
5010019		Fuel Oil Consumed	4,595,748	0	4,595,748	0
5010027		Gypsum handling/disposal costs	269,084	0	269,084	0
5010028		Gypsum Sales Proceeds	(511,873)	0	(511,873)	0
5470004		Fuel - Gas Turb - Purch / Hand	142	0	142	0
		Fuel Expense Total	**208,850,481**	**14**	**208,850,458**	**9**
5010005		Fuel - Deferred	(14,335,070)	0	(14,335,070)	0
		Deferred Fuel Expense	**(14,335,070)**	**-**	**(14,335,070)**	**-**
		Over Under Fuel Expense				
		Fuel for Electric Generation	**194,515,411**	**14**	**194,515,388**	**9**
5010029		Gypsum handling/dspl-Affilat	120,641	0	120,641	0
		Fuel from Affiliates for Electric Generation	**120,641**	**-**	**120,641**	**-**
5090000		Allow Consum Title IV SO2	6,473,558	0	6,473,558	0
5090001		Allowance Consumption - NOx	27,969	0	27,969	0
5090005		An NOx Cons Exp	93,948	0	93,948	0
		Allowances - Consumption	**6,595,474**	**-**	**6,595,474**	**-**
5020002		Urea Expense	3,754,244	0	3,754,244	0
5020003		Trona Expense	236,171	0	236,171	0
5020004		Limestone Expense	2,702,427	0	2,702,427	0
5020005		Polymer expense	61,541	0	61,541	0
5020007		Lime Hydrate Expense	13,407	0	13,407	0
		Emissions Control - Chemicals	**6,767,788**	**-**	**6,767,788**	**-**
		Total Fuel for Electric Generation	**207,999,315**	**14**	**207,999,292**	**9**
		Memo: NonAff Fuel/Allow/Emissions	***207,878,674***	***14***	***207,878,651***	***9***
5550004		Purchased Power-Pool Capacity	181,949	0	181,949	0
5550005		Purchased Power - Pool Energy	676,093	0	676,093	0
5550027		Purch Pwr-Non-Fuel Portion-Aff	32,260,553	0	32,260,553	0
5550029		Purch Power-Assoc-Trnsfr Price	0	297,290,976	0	0
5550045		Purch Power-Fuel Portion-Affil	44,555,768	0	44,555,768	0
5550101		Purch Power-Pool Non-Fuel -Aff	168,508	0	168,508	0
5550102		Pur Power-Pool NonFuel-OSS-Aff	214,985	0	214,985	0
		Purchased Electricity from AEP - Affiliates	**78,057,856**	**297,290,976**	**78,057,856**	**-**
5550000		Purchased Power	146	0	143	3
5550001		Purch Pwr-NonTrading-Nonassoc	481,454	0	481,454	0
5550032		Gas-Conversion-Mone Plant	3,333	0	3,333	0
5550039		PJM Inadvertent Mtr Res-OSS	(60,217)	0	(60,217)	0
5550040		PJM Inadvertent Mtr Res-LSE	(28,825)	0	(28,825)	0
5550041		PJM Ancillary Serv -Sync	5,492	0	5,492	0

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09B V2014-08-31	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Aug 2014	Kentucky Power Company - Distribution 110 Actual YTD Aug 2014	Kentucky Power Company - Generation 117 Actual YTD Aug 2014	Kentucky Power Company - Transmission 180 Actual YTD Aug 2014
5550074	PJM Reactive-Charge	(11,793)	0	(11,793)	0
5550076	PJM Black Start-Charge	1,067,169	0	1,067,169	0
5550077	PJM Black Start-Credit	(7)	0	(7)	0
5550078	PJM Regulation-Charge	1,650,677	0	1,650,677	0
5550079	PJM Regulation-Credit	(398,955)	0	(398,955)	0
5550083	PJM Spinning Reserve-Charge	1,338,945	0	1,338,945	0
5550084	PJM Spinning Reserve-Credit	(322,622)	0	(322,622)	0
5550090	PJM 30m Suppl Rserv Charge LSE	386,637	0	386,637	0
5550099	PJM Purchases-non-ECR-Auction	1,452,744	0	1,452,744	0
5550100	Capacity Purchases-Auction	55,122	0	55,122	0
5550107	Capacity purchases - Trading	177,879	0	177,879	0
	Purchased Electricity for Resale - NonAffiliated	**5,797,180**	**-**	**5,797,177**	**3**
	Purchased Gas for Resale - Affiliated	**-**	**-**	**-**	**-**
	Purchased Gas for Resale - NonAffiliated	**-**	**-**	**-**	**-**
	Total Purchased Power	**83,855,036**	**297,290,976**	**83,855,033**	**3**
	GROSS MARGIN	**291,139,618**	**110,381,963**	**138,550,502**	**65,693,908**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	2,543,898	131	2,543,653	113
5000001	Oper Super & Eng-RATA-Affil	52,712	0	52,712	0
5020000	Steam Expenses	1,672,958	0	1,672,958	0
5050000	Electric Expenses	369,215	0	369,215	0
5060000	Misc Steam Power Expenses	5,176,954	130	5,176,741	83
5060002	Misc Steam Power Exp-Assoc	38,396	0	38,396	0
5060003	Removal Cost Expense - Steam	(77,086)	0	(77,086)	0
5060004	NSR Settlement Expense	(1,428)	0	(1,428)	0
5060025	Misc Stm Pwr Exp Environmental	(11)	0	(11)	0
	Steam Generation Op Exp	**9,775,608**	**261**	**9,775,151**	**196**
	Nuclear Generation Op Exp	**-**	**-**	**-**	**-**
	Hydro Generation Op Exp	**-**	**-**	**-**	**-**
5560000	Sys Control & Load Dispatching	357,070	6	356,990	74
5570000	Other Expenses	1,184,390	342	1,183,875	173
5570007	Other Pwr Exp - Wholesale RECs	12,054	12,054	0	0
5570008	Other Pwr Exp - Voluntary RECs	40	40	0	0
5757000	PJM Admin-MAM&SC- OSS	398,018	0	398,018	0
5757001	PJM Admin-MAM&SC- Internal	496,934	0	496,934	(0)
	Other Generation Op Exp	**2,448,506**	**12,442**	**2,435,818**	**247**
5600000	Oper Supervision & Engineering	704,646	2,722	5,948	695,976
5611000	Load Dispatch - Reliability	5,641	0	0	5,641
5612000	Load Dispatch-Mntr&Op TransSys	575,324	45	75	575,204
5614000	PJM Admin-SSC&DS-OSS	354,316	0	354,316	0
5614001	PJM Admin-SSC&DS-Internal	432,713	0	432,713	0
5614007	RTO Admin Default LSE	3,874	0	3,539	335
5614008	PJM Admin Defaults OSS	2,417	0	2,417	0
5615000	Reliability,Plng&Stds Develop	65,366	5,353	8,611	51,402
5618000	PJM Admin-RP&SDS-OSS	89,080	0	89,080	0
5618001	PJM Admin-RP&SDS- Internal	107,791	0	107,791	0
5620001	Station Expenses - Nonassoc	267,842	3,443	0	264,400
5630000	Overhead Line Expenses	119,093	21	0	119,072
5650002	Transmssn Elec by Others-NAC	124,875	0	124,875	0
5650007	Tran Elec by Oth-Aff-Trn Price	0	23,142,332	0	0
5650012	PJM Trans Enhancement Charge	2,772,279	0	2,772,279	0
5650015	PJM TO Serv Exp - Aff	26,399	0	26,399	0
5650016	PJM NITS Expense - Affiliated	3,431,604	0	3,431,604	0
5650019	Affil PJM Trans Enhncement Exp	236,625	0	236,625	0
5650020	PROVISION RTO Affil Expense	1,021,163	0	1,021,163	0
5660000	Misc Transmission Expenses	878,005	6,489	9,047	862,469
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	344,423
5757002	SPP Admin-MAM&SC	0	0	0	0
	Transmission Op Exp	**11,219,302**	**23,160,405**	**8,626,480**	**2,919,171**
5800000	Oper Supervision & Engineering	514,142	504,168	3,774	6,200
5810000	Load Dispatching	2,559	2,018	0	541
5820000	Station Expenses	137,143	133,851	0	3,292
5830000	Overhead Line Expenses	669,999	670,131	(135)	3
5840000	Underground Line Expenses	70,429	70,257	126	46
5841000	Oper of Energy Storage Equip	0	0	0	0
5850000	Street Lighting & Signal Sys E	106,096	106,096	0	0
5860000	Meter Expenses	528,026	526,600	990	437

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5870000	Customer Installations Exp	108,062	108,062	0	0
5880000	Miscellaneous Distribution Exp	2,547,478	2,521,765	6,239	19,475
5890001	Rents - Nonassociated	1,125,849	1,125,849	0	0
5890002	Rents - Associated	45,864	45,864	0	0
	Distribution Op Exp	**5,855,648**	**5,814,661**	**10,993**	**29,994**
9010000	Supervision - Customer Accts	196,562	196,488	54	20
9020000	Meter Reading Expenses	7,547	7,184	265	99
9020001	Customer Card Reading	325	97	167	61
9020002	Meter Reading - Regular	294,694	294,694	0	0
9020003	Meter Reading - Large Power	37,779	37,779	0	0
9020004	Read-In & Read-Out Meters	38,414	38,414	0	0
9030000	Cust Records & Collection Exp	233,881	229,328	335	4,218
9030001	Customer Orders & Inquiries	1,667,664	1,666,785	675	204
9030002	Manual Billing	27,021	26,148	5	868
9030003	Postage - Customer Bills	526,472	526,472	0	0
9030004	Cashiering	96,521	95,844	350	326
9030005	Collection Agents Fees & Exp	43,977	43,977	0	0
9030006	Credit & Oth Collection Activ	502,699	502,651	36	12
9030007	Collectors	390,256	390,256	0	0
9030009	Data Processing	108,856	108,843	9	3
9040007	Uncoll Accts - Misc Receivable	(56,466)	(56,466)	0	0
9050000	Misc Customer Accounts Exp	18,896	18,896	0	0
9070000	Supervision - Customer Service	104,579	104,576	2	2
9070001	Supervision - DSM	(11)	(4)	(4)	(3)
9080000	Customer Assistance Expenses	324,379	324,380	(1)	(0)
9080001	DSM-Customer Advisory Grp	924	924	0	0
9080009	Cust Assistance Expense - DSM	3,057,231	3,056,443	569	220
9090000	Information & Instruct Advrtis	54,612	16,574	27,688	10,350
9100000	Misc Cust Svc&Informational Ex	30,412	11,767	13,728	4,918
	Customer Service and Information Op Exp	**7,707,224**	**7,642,049**	**43,877**	**21,298**
9120000	Demonstrating & Selling Exp	17,345	17,345	0	0
9120003	Demo & Selling Exp - Area Dev	(321)	(321)	0	0
	Sales Expenses	**17,024**	**17,024**	-	-
	Memo: Insurance (9240 9250)	**972,355**	**454,814**	**371,156**	**146,384**
9200000	Administrative & Gen Salaries	6,323,044	2,800,747	2,609,711	912,585
9210001	Off Supl & Exp - Nonassociated	465,733	274,013	152,114	39,606
9210003	Office Supplies & Exp - Trnsf	9	6	2	0
9220000	Administrative Exp Trnsf - Cr	(410,902)	(410,902)	0	(0)
9220001	Admin Exp Trnsf to Cnstrctn	(309,836)	(309,836)	0	0
9220004	Admin Exp Trnsf to ABD	(1,954)	(950)	0	(1,004)
9230001	Outside Svcs Empl - Nonassoc	948,241	448,266	375,554	124,421
9230002	Outside Svcs Empl - Assoc	(0)	(0)	(0)	0
9230003	AEPSC Billed to Client Co	(132,100)	(35,627)	(56,251)	(40,223)
9240000	Property Insurance	345,390	112,620	102,175	130,595
9250000	Injuries and Damages	799,840	555,081	206,558	38,201
9250001	Safety Dinners and Awards	3,126	1,403	1,375	349
9250002	Emp Accident Prvntion-Adm Exp	6,204	3,942	1,611	651
9250004	Injuries to Employees	2,459	0	2,459	0
9250006	Wkrs Cmpnstn Pre&Slf Ins Prv	(147,038)	(128,647)	(6,224)	(12,167)
9250007	Prsnal Injries&Prop Dmage-Pub	67,250	555	66,665	30
9250010	Frg Ben Loading - Workers Comp	(104,876)	(90,139)	(3,463)	(11,275)
9260000	Employee Pensions & Benefits	3,116	3,116	0	0
9260001	Edit & Print Empl Pub-Salaries	17,840	6,441	7,344	4,055
9260002	Pension & Group Ins Admin	25,312	12,454	11,585	1,273
9260003	Pension Plan	3,370,147	1,529,075	1,658,668	182,404
9260004	Group Life Insurance Premiums	99,382	39,813	52,929	6,640
9260005	Group Medical Ins Premiums	3,396,640	1,681,538	1,455,229	259,873
9260006	Physical Examinations	1	0	0	1
9260007	Group L-T Disability Ins Prem	12,082	8,227	3,295	560
9260009	Group Dental Insurance Prem	142,978	73,130	60,397	9,450
9260010	Training Administration Exp	446	194	198	54
9260012	Employee Activities	2,040	757	668	615
9260014	Educational Assistance Pmts	1,438	900	455	83
9260019	Employee Benefit Exp - COLI	10,000	0	10,000	0
9260021	Postretirement Benefits - OPEB	(2,440,284)	(1,163,096)	(1,115,438)	(161,751)
9260027	Savings Plan Contributions	1,441,770	630,789	741,787	69,194
9260036	Deferred Compensation	4,437	4,437	0	0
9260037	Supplemental Pension	159	159	0	0
9260040	SFAS 112 Postemployment Benef	432,161	0	432,161	0
9260050	Frg Ben Loading - Pension	(1,013,704)	(708,273)	(236,636)	(68,795)

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9260051	Frg Ben Loading - Grp Ins	(1,199,752)	(831,314)	(267,302)	(101,137)
9260052	Frg Ben Loading - Savings	(473,573)	(292,241)	(143,110)	(38,222)
9260053	Frg Ben Loading - OPEB	330,567	267,845	27,835	35,287
9260055	IntercoFringeOffset- Don't Use	(1,162,687)	(251,043)	(793,109)	(118,535)
9260057	Postret Ben Medicare Subsidy	410,849	166,127	228,962	15,761
9260058	Frg Ben Loading - Accrual	(92,694)	(41,084)	(45,556)	(6,054)
9260060	Amort-Post Retirement Benefit	144,413	86,387	47,471	10,555
9270000	Franchise Requirements	95,544	95,544	0	0
9280000	Regulatory Commission Exp	24,857	8,918	10,211	5,728
9280001	Regulatory Commission Exp-Adm	0	0	0	0
9280002	Regulatory Commission Exp-Case	100,793	23,013	63,063	14,717
9301000	General Advertising Expenses	848	298	362	187
9301001	Newspaper Advertising Space	9,643	3,473	4,007	2,163
9301002	Radio Station Advertising Time	4,440	1,606	1,836	998
9301010	Publicity	2,252	808	959	485
9301012	Public Opinion Surveys	16,858	16,854	0	4
9301015	Other Corporate Comm Exp	8,883	6,116	1,877	890
9302000	Misc General Expenses	167,713	82,983	48,555	36,176
9302003	Corporate & Fiscal Expenses	21,336	4,663	15,345	1,329
9302004	Research, Develop&Demonstr Exp	3,341	3,341	0	0
9302458	AEPSC Non Affiliated expenses	(0)	0	(0)	0
9310001	Rents - Real Property	70,846	70,846	0	0
9310002	Rents - Personal Property	173,792	116,979	49,168	7,644
	Administration & General	**12,018,818**	**4,880,114**	**5,785,304**	**1,353,400**
4111005	Accretion Expense	646,472	0	646,472	0
	Accretion	**646,472**	**-**	**646,472**	**-**
4116000	Gain From Disposition of Plant	(2,680)	(2,680)	0	0
	Loss/(Gain) on Utility Plant	**(2,680)**	**(2,680)**	**-**	**-**
9302006	Assoc Bus Dev - Materials Sold	32,030	32,030	0	0
9302007	Assoc Business Development Exp	59,579	35,616	76	23,888
	Associated Business Development Expenses	**91,609**	**67,646**	**76**	**23,888**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4010001	Operation Exp - Nonassociated	(343)	0	(343)	0
4265009	Factored Cust A/R Exp - Affil	645,958	645,958	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,215,183	1,215,183	0	0
	Opr Exp and Factored A/R	**1,860,798**	**1,861,141**	**(343)**	**-**
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	52,218	17,833	23,658	10,727
4265007	Regulatory Expenses	1,932	690	808	434
	Expense of Non-Utility Operation	**54,149**	**18,523**	**24,466**	**11,160**
4210009	Misc Non-Op Exp - NonAssoc	5,557	1,463	3,176	918
	Misc NonOp Expenses - NonAssoc	**5,557**	**1,463**	**3,176**	**918**
4261000	Donations	282,698	196,110	73,768	12,820
	Donation Contributions	**282,698**	**196,110**	**73,768**	**12,820**
4263001	Penalties	62,111	23,922	24,133	14,057
	Provision for Penalties	**62,111**	**23,922**	**24,133**	**14,057**
4264000	Civic & Political Activities	162,499	59,857	64,757	37,885
	Civic & Political Activities	**162,499**	**59,857**	**64,757**	**37,885**
4265002	Other Deductions - Nonassoc	1,297	449	563	284
4265033	Transition Costs	5,267	0	5,267	0
	Other Deductions	**6,564**	**449**	**5,830**	**284**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**2,434,377**	**2,161,465**	**195,787**	**77,125**
	Operational Expenses	**52,211,909**	**43,753,387**	**27,519,959**	**4,425,318**
5100000	Maint Supv & Engineering	2,515,026	273	2,514,713	41
5110000	Maintenance of Structures	1,166,185	0	1,166,185	0
5120000	Maintenance of Boiler Plant	11,175,675	(25)	11,175,700	0
5130000	Maintenance of Electric Plant	1,889,175	0	1,889,219	(44)
5140000	Maintenance of Misc Steam Plt	1,012,386	0	1,012,386	0
	Steam Generation Maintenance	**17,758,447**	**248**	**17,758,202**	**(3)**
5280000	Maint Supv & Engineering	779	0	779	0
5300000	Maint of Reactor Plant Equip	767	0	739	27
	Nuclear Generation Maintenance	**1,546**	**-**	**1,519**	**27**
	Hydro Generation Maintenance	-	-	-	-
5530001	Maint of Gen Plant - Gas Turb	(3)	0	0	(3)
	Other Generation Maintenance	**(3)**	**-**	**-**	**(3)**
5680000	Maint Supv & Engineering	57,017	35	0	56,983

American Electric Power

INCOME STATEMENT

GLS8016
YTD Aug 2014
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Layout: GLS8016

09B V2014-08-31	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Aug 2014	Kentucky Power Company - Distribution 110 Actual YTD Aug 2014	Kentucky Power Company - Generation 117 Actual YTD Aug 2014	Kentucky Power Company - Transmission 180 Actual YTD Aug 2014
5690000	Maintenance of Structures	4,580	0	0	4,580
5691000	Maint of Computer Hardware	12,822	35	27	12,759
5692000	Maint of Computer Software	177,047	3,370	0	173,677
5693000	Maint of Communication Equip	11,135	0	0	11,135
5700000	Maint of Station Equipment	496,589	18,215	1	478,373
5710000	Maintenance of Overhead Lines	2,393,494	(1,653)	62	2,395,085
5720000	Maint of Underground Lines	260	0	0	260
5730000	Maint of Misc Trnsmssion Plt	161,183	0	0	161,183
	Transmission Maintenance	**3,314,128**	**20,002**	**90**	**3,294,036**
5900000	Maint Supv & Engineering	1,835	1,800	(1)	36
5910000	Maintenance of Structures	7,481	6,885	0	596
5920000	Maint of Station Equipment	475,415	457,861	33	17,521
5930000	Maintenance of Overhead Lines	21,308,949	21,309,288	2,576	(2,914)
5930001	Tree and Brush Control	237,368	237,368	0	0
5930008	Maint Ovh Lines Strm Exp-OvUnd	1,292	1,292	0	0
5930010	Storm Expense Amortization	3,132,296	3,132,296	0	0
5940000	Maint of Underground Lines	56,884	56,884	0	0
5950000	Maint of Lne Trnf Rglators&Dvi	43,861	43,861	0	0
5960000	Maint of Strt Lghtng & Sgnal S	38,369	38,369	0	0
5970000	Maintenance of Meters	54,913	52,031	0	2,882
5980000	Maint of Misc Distribution Plt	121,867	120,763	0	1,104
	Distribution Maintenance	**25,480,550**	**25,458,718**	**2,609**	**19,224**
9350000	Maintenance of General Plant	149	0	0	149
9350001	Maint of Structures - Owned	182,261	179,976	(24)	2,309
9350002	Maint of Structures - Leased	37,577	35,912	1,078	586
9350003	Maint of Prpty Held Fture Use	451	(1)	454	(1)
9350006	Maint of Carrier Equipment	13	13	0	0
9350012	Maint of Data Equipment	346	0	346	0
9350013	Maint of Cmmncation Eq-Unall	456,860	420,600	36,260	0
9350015	Maint of Office Furniture & Eq	372,510	192,360	180,150	0
9350016	Maintenance of Video Equipment	120	120	0	0
9350019	Maint of Gen Plant-SCADA Equ	316	313	2	0
9350023	Site Communications Services	286	0	286	0
9350024	Maint of DA-AMI Comm Equip	154	154	0	0
	Administration & General Maintenance	**1,051,041**	**829,447**	**218,552**	**3,042**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**47,605,709**	**26,308,414**	**17,980,972**	**3,316,324**
	Total Operational and Maintenance Expenses	**99,817,619**	**70,061,801**	**45,500,930**	**7,741,642**
4040001	Amort of Plant	2,334,358	1,025,948	912,396	396,014
4060001	Amort of Plt Acq Adj	25,744	0	0	25,744
	DDA Amortization	**2,360,102**	**1,025,948**	**912,396**	**421,758**
4073000	Regulatory Debits	192,724	0	0	192,724
	DDA Regulatory Debits	**192,724**	-	-	**192,724**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**2,552,826**	**1,025,948**	**912,396**	**614,482**
4030001	Depreciation Exp	59,722,652	16,937,502	37,019,383	5,765,767
	DDA Depreciation	**59,722,652**	**16,937,502**	**37,019,383**	**5,765,767**
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	324,449	0	324,449	0
	DDA Asset Retirement Obligation	**324,449**	-	**324,449**	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**60,047,101**	**16,937,502**	**37,343,832**	**5,765,767**
	Depreciation and Amortization	**62,599,927**	**17,963,450**	**38,256,228**	**6,380,249**
	Franchise Taxes	-	-	-	-
408100613	State Gross Receipts Tax	(5,942)	1	(5,943)	0
409100614	State Gross Receipts Tax	33,930	2	33,928	0
	Revenue-kWhr Taxes	**27,988**	**3**	**27,985**	-
4081002	FICA	2,674,330	1,147,825	1,392,108	134,397
4081003	Federal Unemployment Tax	18,348	7,954	9,424	969
4081007	State Unemployment Tax	73,463	30,195	39,414	3,854
4081033	Fringe Benefit Loading - FICA	(845,674)	(520,607)	(255,025)	(70,042)
4081034	Fringe Benefit Loading - FUT	(6,077)	(3,540)	(2,170)	(367)
4081035	Fringe Benefit Loading - SUT	(16,319)	(7,901)	(7,586)	(832)
	Payroll Taxes	**1,898,070**	**653,926**	**1,176,166**	**67,979**
408102014	State Business Occup Taxes	2,648,380	0	2,648,380	0
	Capacity Taxes	**2,648,380**	-	**2,648,380**	-
408100509	Real & Personal Property Taxes	3,975	3,907	0	69
408100510	Real Personal Property Taxes	131	131	0	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Aug 2014
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Layout: GLS8016

098 V2014-08-31	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Aug 2014	Kentucky Power Company - Distribution 110 Actual YTD Aug 2014	Kentucky Power Company - Generation 117 Actual YTD Aug 2014	Kentucky Power Company - Transmission 180 Actual YTD Aug 2014
408100512	Real Personal Property Taxes	1,586,369	111,154	1,447,634	27,581
408100513	Real Personal Property Taxes	7,253,984	3,995,496	1,034,568	2,223,920
408102910	Real-Pers Prop Tax-Cap Leases	12	12	0	0
408102913	Real-Pers Prop Tax-Cap Leases	1,038	790	68	180
408102914	Real-Pers Prop Tax-Cap Leases	16,478	10,816	2,982	2,680
408103613	Real Prop Tax-Cap Leases	(1,473)	(1,473)	0	0
408103614	Real Prop Tax-Cap Leases	17,000	17,000	0	0
408200513	Real Personal Property Taxes	37,736	6,448	0	31,288
	Property Taxes	**8,915,251**	**4,144,280**	**2,485,253**	**2,285,718**
408101813	St Publ Serv Comm Tax-Fees	473,122	473,122	0	0
408101814	St Publ Serv Comm Tax-Fees	178,259	178,259	0	0
	Regulatory Fees	**651,381**	**651,381**	-	-
408101414	Federal Excise Taxes	1,745	0	1,745	0
	Production Taxes	**1,745**	-	**1,745**	-
408101714	St Lic Rgstrion Tax-Fees	240	240	0	0
408101900	State Sales and Use Taxes	(342,470)	(156,655)	(178,775)	(7,040)
408101912	State Sales and Use Taxes	218,039	89,065	119,078	9,896
408101913	State Sales and Use Taxes	1,295	1,295	0	0
408101914	State Sales and Use Taxes	11,008	11,008	0	0
408102214	Municipal License Fees	425	425	0	0
	Miscellaneous Taxes	**(111,464)**	**(54,622)**	**(59,697)**	**2,856**
	Other Non-Income Taxes	**(109,719)**	**(54,622)**	**(57,953)**	**2,856**
	Taxes Other Than Income Taxes	**14,031,351**	**5,394,968**	**6,279,831**	**2,356,553**
	TOTAL OPERATING EXPENSES	**176,448,897**	**93,420,219**	**90,036,989**	**16,478,444**
	Memo: SEC Total Operating Expenses	**468,303,248**	**390,711,209**	**381,891,313**	**16,478,455**
	OPERATING INCOME	**114,690,721**	**16,961,744**	**48,513,513**	**49,215,464**
	NON OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	98,488	46,698	47,829	3,961
	Interest & Dividend NonAffiliated	**98,488**	**46,698**	**47,829**	**3,961**
4190001	Interest Inc - Assoc Non CBP	14,193	14,193	0	0
4190005	Interest Income - Assoc CBP	42,298	(5,458)	(40,505)	88,260
	Interest & Dividend Affiliated	**56,491**	**8,735**	**(40,505)**	**88,260**
	Total Interest & Dividend Income	**154,979**	**55,433**	**7,324**	**92,221**
4210039	Carrying Charges	41,251	0	0	41,251
	Interest & Dividend Carrying Charge	**41,251**	-	-	**41,251**
	Memo: Total Interest & Dividend Income w/ Carrying	**196,230**	**55,433**	**7,324**	**133,472**
4191000	Allw Oth Fnds Usd Dirng Cnstr	3,216,347	276,411	1,923,914	1,016,022
	AFUDC	**3,216,347**	**276,411**	**1,923,914**	**1,016,022**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
4270002	Int on LTD - Install Pur Contr	7,777	7,777	0	0
	Interest LTD IPC	**7,777**	**7,777**	-	-
4300001	Interest Exp - Assoc Non-CBP	700,000	269,022	220,347	210,631
	Interest LTD Notes Payable - Affiliated	**700,000**	**269,022**	**220,347**	**210,631**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	22,665,804	8,710,865	7,134,770	6,820,169
	Interest LTD Senior Unsecured	**22,665,804**	**8,710,865**	**7,134,770**	**6,820,169**
4270012	PCRB Interest Exp-Assoc	14,193	14,193	0	0
	Interest LTD Other - Affil	**14,193**	**14,193**	-	-
4270005	Int on LTD - Other LTD	1,942,014	1,948,611	(6,597)	0
	Interest LTD Other - NonAffil	**1,942,014**	**1,948,611**	**(6,597)**	-
	Interest on Long-Term Debt	**25,329,788**	**10,950,469**	**7,348,520**	**7,030,800**
4300003	Int to Assoc Co - CBP	28,026	4,289	169,411	(145,673)
	Interest STD - Affil	**28,026**	**4,289**	**169,411**	**(145,673)**
4310007	Lines Of Credit	523,771	208,655	265,181	49,935
	Interest STD - NonAffil	**523,771**	**208,655**	**265,181**	**49,935**
	Interest on Short Term Debt	**551,797**	**212,944**	**434,591**	**(95,738)**
4280002	Amrtz Debt Dscnt&Exp-Inst Pur	3,394	0	3,394	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	314,124	120,724	98,880	94,520
	Amort of Debt Disc. Prem & Exp	**317,518**	**120,724**	**102,274**	**94,520**
4281004	Amrtz Loss Rcquired Debt-Dbnt	22,432	8,621	7,061	6,750
	Amort Loss on Reacquired Debt	**22,432**	**8,621**	**7,061**	**6,750**
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	70,155	20,568	41,533	8,054

American Electric Power

INCOME STATEMENT

GLS8016
YTD Aug 2014
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Layout: GLS8016

09B V2014-08-31	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Aug 2014	Kentucky Power Company - Distribution 110 Actual YTD Aug 2014	Kentucky Power Company - Generation 117 Actual YTD Aug 2014	Kentucky Power Company - Transmission 180 Actual YTD Aug 2014
4310002	Interest on Customer Deposits	18,792	18,792	0	0
4310023	Interest Expense - State Tax	2,203	1,098	1,052	53
	Other Interest - NonAffil	**91,150**	**40,458**	**42,585**	**8,107**
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Allw Brrwed Fnds Used Cnstr-Cr	(1,622,775)	(136,277)	(982,559)	(503,939)
	AFUDC-Borrowed Funds	**(1,622,775)**	**(136,277)**	**(982,559)**	**(503,939)**
	Total Interest Charges	**24,689,911**	**11,196,938**	**6,952,473**	**6,540,500**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**93,413,386**	**6,096,650**	**43,492,278**	**43,824,458**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes UOI - Federal	31,871,558	4,014,230	15,500,599	12,356,729
4092001	Inc Tax Oth Inc&Ded-Federal	(396,116)	(290,730)	(75,301)	(30,085)
	Federal Current Income Tax	**31,475,442**	**3,723,501**	**15,425,298**	**12,326,644**
4101001	Prov Def I/T Utl Op Inc-Fed	29,483,653	2,970,210	23,993,959	2,499,484
4102001	Prov Def I/T Oth I&D - Federal	479,007	250,169	182,047	46,791
4111001	Prv Def I/T-Cr Utl Op Inc-Fed	(32,266,914)	(4,885,923)	(26,418,948)	(962,043)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(40,885)	0	(40,885)	0
	Federal Deferred Income Tax	**(2,365,139)**	**(1,665,544)**	**(2,283,827)**	**1,584,231**
4114001	ITC Adj. Utility Oper - Fed	(64,025)	(10,080)	(15,408)	(38,537)
	Federal Investment Tax Credits	**(64,025)**	**(10,080)**	**(15,408)**	**(38,537)**
	Federal Income Taxes	**29,046,278**	**2,047,877**	**13,126,063**	**13,872,338**
409100214	Income Taxes UOI - State	5,563,406	230,301	3,186,765	2,146,341
409200214	Inc Tax Oth Inc Ded - State	(68,754)	(50,462)	(13,070)	(5,222)
	State Current Income Tax	**5,494,653**	**179,839**	**3,173,695**	**2,141,119**
4111002	Prv Def I/T-Cr UtlOpInc-State	(407,680)	0	(407,680)	0
	State Deferred Income Tax	**(407,680)**	-	**(407,680)**	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	**5,086,973**	**179,839**	**2,766,015**	**2,141,119**
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	**34,133,251**	**2,227,716**	**15,892,078**	**16,013,457**
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**59,280,135**	**3,868,934**	**27,600,200**	**27,811,001**
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	**59,280,135**	**3,868,934**	**27,600,200**	**27,811,001**
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	**59,280,135**	**3,868,934**	**27,600,200**	**27,811,001**
	NET INCOME (LOSS) NODE before PS	**59,280,135**	**3,868,934**	**27,600,200**	**27,811,001**
	Double Check on Net Income Node after PS	-	(0)	(0)	-

Reserved Section

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Aug 2014
09/10/2014 15:11

Layout : GLS8216
09B V2014-08- Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Aug 2014	YTD Aug 2014	YTD Aug 2014	YTD Aug 2014
ASSETS				
Cash and Cash Equivalents	810,262	810,262	0	0
Other Cash Deposits	0	0	0	0
Customers	25,331,648	10,000,317	12,941,262	2,390,069
Accrued Unbilled Revenues	(4,813,853)	(5,204,920)	391,067	0
Miscellaneous Accounts Receivable	29,468,928	38,062,175	64,045,034	26,607,259
Allowances for Uncollectible Accounts	(23,817)	(16,914)	(6,903)	0
Accounts Receivable	49,962,906	42,840,659	77,370,460	28,997,328
Advances to Affiliates	3,533,978	(37,598,764)	(21,689,743)	62,822,485
Fuel, Materials and Supplies	56,945,128	2,234,821	53,778,668	931,638
Risk Management Contracts - Current	3,837,119	0	3,837,119	0
Margin Deposits	2,100,750	17,101	2,083,649	0
Unrecovered Fuel - Current	11,484,432	0	11,484,432	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	3,066,765	2,221,202	678,169	167,394
TOTAL CURRENT ASSETS	131,741,339	10,525,281	127,542,753	92,918,846
Electric Production	1,148,159,825	761,225,340	1,612,143,686	517,884,186
Electric Transmission	521,112,905	0	0	0
Electric Distribution	715,404,818	0	0	0
General Property, Plant and Equipment	512,105,098	199,571	4,169,386	1,160,479
Construction Work-In-Progress	76,043,985	10,330,592	29,963,972	35,749,421
TOTAL PROPERTY, PLANT and EQUIPMENT	2,972,826,632	771,755,503	1,646,277,044	554,794,085
less: Accumulated Depreciation and Amortization	(995,563,291)	(244,745,464)	(579,434,784)	(171,383,043)
NET PROPERTY, PLANT and EQUIPMENT	1,977,263,341	527,010,039	1,066,842,260	383,411,042
Net Regulatory Assets	216,056,113	101,571,859	58,766,106	55,718,148
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	1,587,540	0	1,587,540	0
Employee Benefits and Pension Assets	15,542,642	(20,737)	15,120,574	442,804
Other Non Current Assets	8,734,344	3,322,975	3,759,709	1,651,660
TOTAL OTHER NON-CURRENT ASSETS	241,920,639	104,874,097	79,233,928	57,812,613
TOTAL ASSETS	2,350,925,320	642,409,417	1,273,618,941	534,142,501
LIABILITIES				
Accounts Payable	78,112,876	73,465,810	98,336,469	5,556,137
Advances from Affiliates	0	0	0	0
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	265,000,000	0	265,000,000	0
Long-Term Debt Due Within One Year - Affiliated	20,000,000	7,614,600	6,233,800	6,151,600
Risk Management Liabilities	1,831,256	2,768	1,828,488	0
Accrued Taxes	38,986,822	8,373,875	10,862,858	19,750,089
Memo: Property Taxes	12,191,506	6,141,136	2,265,144	3,785,226
Accrued Interest	12,452,271	4,739,189	3,911,208	3,801,874
Risk Management Collateral	307,092	0	307,092	0
Utility Customer Deposits	25,085,924	25,085,924	0	0
Deposits - Customer and Collateral	25,393,016	25,085,924	307,092	0
Over-Recovered Fuel Costs - Current	0	0	0	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,143,676	491,575	508,464	143,637
Tax Collections Payable	2,085,686	1,993,936	85,431	6,318
Revenue Refunds - Accrued	1,151,084	0	31,488	1,119,596
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	1,734,690	671,185	977,408	86,097
Accrued Rents	8,687	8,687	0	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Aug 2014
09/10/2014 15:11

Layout : GLS8216

09B V2014-08-	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
		YTD Aug 2014	YTD Aug 2014	YTD Aug 2014	YTD Aug 2014
	Accrued ICP	5,199,379	2,021,483	2,979,674	198,222
	Accrued Vacations	5,081,679	2,036,239	2,779,745	265,695
	Misc Employee Benefits	1,489,490	558,361	903,880	27,248
	Payroll Deductions	176,713	78,800	88,311	9,602
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	697,491	279,373	397,609	20,508
2530022	Customer Advance Receipts	1,600,117	1,600,117	0	0
	Customer Advance	1,600,117	1,600,117	0	0
2420511	Control Cash Disburse Account	637,215	637,215	0	0
	Control Cash Disbursement Account	637,215	637,215	0	0
	JMG Liability	0	0	0	0
2420088	Econ. Development Fund Curr	116,500	0	116,500	0
2420506	Est Financing Cost - Bonds	(126,893)	0	(126,893)	0
2420512	Unclaimed Funds	64,349	64,349	0	0
2420542	Acc Cash Franchise Req	59,796	59,796	0	0
242059214	Sales Use Tax - Lease Equip	665	257	218	190
2420643	Accrued Audit Fees	83,712	20,557	50,257	12,898
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	246,141	0	246,141	0
2530050	Deferred Rev -Pole Attachments	271,129	271,129	0	0
2530112	Other Deferred Credits-Curr	221,616	0	221,616	0
2530124	Contr in Aid of Constr Advance	87,123	87,123	0	0
2530177	Deferred Rev-Bonus Lease Curr	431,564	0	431,564	0
	Misc Current and Accrued Liabilities	2,010,228	503,211	1,493,929	13,088
	Current Other and Accrued Liabilities	21,872,458	10,388,608	9,737,475	1,746,375
	Other Current Liabilities	23,016,134	10,880,183	10,245,939	1,890,011
	TOTAL CURRENT LIABILITIES	464,792,374	130,162,349	396,725,853	37,149,711
	Long-Term Debt - Affiliated	0	0	0	0
	Long-Term Debt - Non Affiliated	530,000,000	201,786,900	165,195,700	163,017,400
	Long-Term Debt - Premiums and Discounts Unamort	(500,175)	(190,432)	(155,900)	(153,844)
	Memo - LTD NonAffiliated and Premiums	*529,499,825*	*201,596,468*	*165,039,800*	*162,863,556*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	868,136	5,406	862,730	0
2440022	L/T Liability MTM Collateral	(4,967)	(3,179)	(1,788)	0
	Long-Term Risk Management Liabilities - MTM	863,169	2,227	860,942	0
	Long-Term Risk Management Liabilities	863,169	2,227	860,942	0
	Deferred Income Taxes	553,425,797	168,348,519	265,370,522	119,706,756
	Deferred Investment Tax Credits	61,722	14,085	22,420	25,218
	Regulatory Liabilities and Deferred Credits	22,439,177	(32,633,490)	61,466,863	(6,394,197)
	Memo - Reg Liab and Def ITC	*22,500,899*	*(32,619,405)*	*61,489,283*	*(6,368,979)*
	Asset Retirement Obligation	63,847,132	63,320	63,783,812	0
	Nuclear Decommissioning	0	0	0	0
	Employee Benefits and Pension Obligations	7,896,162	3,100,574	4,698,124	97,463
	Trust Preferred Securities	0	0	0	0
	Cumulative Preferred Stocks of Subs - Mandatory Rede	0	0	0	0
	Obligations Under Capital Leases	3,464,846	1,334,526	1,680,845	449,475
	Def Credits - Income Tax	77,533	42,619	6,599	28,315
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	119,142	119,142	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	4,205	0	4,205	0
2530067	IPP - System Upgrade Credits	274,725	0	0	274,725
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	152,624	152,624	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	94,136	0	0	94,136
2530178	Deferred Rev-Bonus Lease NC	1,582,402	0	1,582,402	0
	Def Credits - Other	2,108,092	152,624	1,586,607	368,861
	Total Other Deferred Credits	2,227,234	271,766	1,586,607	368,861
	Accumulated Provisions - Rate Refund	0	0	0	0
	Accumulated Provisions - Misc	815,500	0	815,500	0

AMERICAN ELECTRIC POWER COMPANY
GLS8216
YTD Aug 2014
09/10/2014 15:11

BALANCE SHEET

Layout : GLS8216

09B V2014-08~ Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	Kentucky Power Int Consol GLS8216 YTD Aug 2014	Kentucky Power Company - 110 YTD Aug 2014	Kentucky Power Company - Generation 117 YTD Aug 2014	Kentucky Power Company - 180 YTD Aug 2014
Other Non-Current Liabilities	7,695,757	1,648,911	5,200,195	846,651
TOTAL NON-CURRENT LIABILITIES	1,185,728,742	342,140,615	566,442,679	277,145,448
TOTAL LIABILITIES	1,650,521,115	472,302,964	963,168,532	314,295,159
Cumulative Pref Stocks of Subs - Not subject Mand Redem	0	0	0	0
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS' EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	517,459,453	106,025,371	327,394,246	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	138,971,059	41,746,046	(20,879,898)	118,104,911
Accumulated Other Comprehensive Income (Loss)	(6,476,308)	(69,013)	(6,351,542)	(55,753)
TOTAL SHAREHOLDERS' EQUITY	700,404,204	170,106,453	310,450,409	219,847,342
Memo: Total Equity	700,404,204	170,106,453	310,450,409	219,847,342
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	2,350,925,320	642,409,417	1,273,618,941	534,142,501
out-of-balance	(0)	0	0	(0)

Reserved Section

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Kentucky Power Corp Consol
Comparative Balance Sheet
August 31, 2013

Run Date: 09/11/2013 15:22

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V KYP_CORP_C(V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
ASSETS			
PRODUCTION	560,485,302.42	558,934,668.00	1,550,634.42
TRANSMISSION	491,316,860.98	490,152,082.00	1,164,778.98
DISTRIBUTION	675,704,425.59	652,615,328.83	23,089,096.76
GENERAL	61,297,632.59	57,451,300.18	3,846,332.41
CONSTRUCTION WORK IN PROGRESS	53,962,501.45	44,281,291.91	9,681,209.54
ELECTRIC UTILITY PLANT	**1,842,766,723.03**	**1,803,434,670.92**	**39,332,052.11**
less Accum Provision - Depre, Depl, Amort.	(649,753,040.22)	(624,238,902.51)	(25,514,137.71)
NET ELECTRIC UTILITY PLANT	**1,193,013,682.81**	**1,179,195,768.41**	**13,817,914.40**
Net NonUtility Property	2,652,288.12	5,498,717.60	(2,846,429.48)
Investment in Subsidiary & Associated	0.00	0.00	0.00
Other Investments	256,941.67	260,727.67	(3,786.00)
Other Special Funds	0.00	0.00	0.00
Allowance - NonCurrent	2,361,233.00	2,361,232.37	0.63
Long Term Energy Trading Contracts	4,536,732.27	6,881,654.77	(2,344,922.50)
OTHER PROPERTY AND INVESTMENTS	**9,807,195.06**	**15,002,332.41**	**(5,195,137.35)**
Cash and Cash Equivalents	975,531.68	1,925,747.09	(950,215.41)
Advances to Affiliates	19,581,843.31	0.00	19,581,843.31
Acct Rec - Customers	12,805,228.95	12,676,052.64	129,176.31
Acct Rec - Miscellaneous	1,881,284.77	3,141,697.43	(1,260,412.66)
Acct Rec - AP for Uncollectible Accounts	(18,278.76)	(141,538.08)	123,259.32
Acct Rec - Associated Companies	7,386,899.99	9,241,088.58	(1,854,188.59)
Fuel Stock	53,427,324.92	69,147,176.47	(15,719,851.55)
Materials and Supplies	20,701,674.75	25,061,279.42	(4,359,604.67)
Accrued Utility Revenues	(2,586,967.47)	816,939.53	(3,403,907.00)
Energy Trading	5,526,179.51	6,174,819.72	(648,640.21)
Prepayments	2,222,119.85	1,569,794.80	652,325.05
Other Current Assets	1,215,451.97	1,660,942.94	(445,490.97)
CURRENT ASSETS	**123,118,293.45**	**131,274,000.53**	**(8,155,707.08)**
REGULATORY ASSETS	**211,682,881.15**	**214,900,829.18**	**(3,217,948.03)**
TOTAL DEFERRED CHARGES	**67,540,729.73**	**78,498,798.33**	**(10,958,068.60)**
TOTAL ASSETS	**1,605,162,782.20**	**1,618,871,728.86**	**(13,708,946.66)**
CAPITALIZATION and LIABILITIES			
COMMON STOCK			
Authorized: 2,000,000 Shares			
Outstanding: 1,009,000 Shares			
Common Stock	50,450,000.00	50,450,000.00	0.00
Premium on Capital Stock	0.00	0.00	0.00
Paid-In-Capital	238,537,532.10	238,341,119.49	196,412.61
Retained Earnings	200,388,641.74	190,818,915.56	9,569,726.18
COMMON SHAREHOLDERS' EQUITY	**489,376,173.84**	**479,610,035.05**	**9,766,138.79**
PS Subject To Mandatory Redemption	0.00	0.00	0.00
PS Not Subject Mandatory Redemption	0.00	0.00	0.00

Kentucky Power Corp Consol
Comparative Balance Sheet
August 31, 2013

Run Date: 09/11/2013 15:22

X_OPR_COS / KYP_CORP_C(	Rpt ID: GLR2200V Layout: GLR2200V / V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
	CUMULATIVE PREFERRED STOCK	**0.00**	**0.00**	**0.00**
	TRUST PREFERRED SECURITIES	**0.00**	**0.00**	**0.00**
	Long-Term Debt Less Amt Due 1 Yr	**549,333,100.00**	**549,221,950.00**	**111,150.00**
	CAPITALIZATION	**1,038,709,273.84**	**1,028,831,985.05**	**9,877,288.79**
	Obligations Under Capital Lease-NonCurrent	1,901,134.15	1,674,300.89	226,833.26
	Accumulated Provision Rate Relief	0.00	1,635,430.00	(1,635,430.00)
	Accumlated Provision - Miscellanous	36,016,285.17	34,033,794.12	1,982,491.05
	Other NonCurrent Liabilities	**37,917,419.32**	**37,343,525.01**	**573,894.31**
	Preferred Stock Due Within 1 Year	0.00	0.00	0.00
	Long-Term Debt Due Within 1 Year	0.00	0.00	0.00
	Accumulated Provision Due Within 1 Year	0.00	0.00	0.00
	Short-Term Debt	0.00	0.00	0.00
	Advances from Affiliates	0.00	13,358,855.63	(13,358,855.63)
	A/P General	20,553,161.87	30,336,776.64	(9,783,614.77)
	A/P Associated Companies	35,137,795.77	41,052,680.18	(5,914,884.41)
	Customer Deposits	24,689,782.89	23,484,964.81	1,204,818.08
	Taxes Accrued	6,654,256.63	6,548,714.64	105,541.99
	Interest Accrued	12,024,236.31	7,166,695.02	4,857,541.29
	Dividends Accrued	0.00	0.00	0.00
	Obligation Under Capital Leases	1,203,227.67	1,403,875.95	(200,648.28)
	Energy Contracts Current	2,740,322.71	3,320,068.02	(579,745.31)
	Other Current and Accrued Liabilities	16,633,186.41	17,797,808.10	(1,164,621.69)
	Current Liabilities	**119,635,970.26**	**144,470,438.99**	**(24,834,468.73)**
	Deferred Income Taxes	**391,482,869.36**	**385,153,166.17**	**6,329,703.19**
	Deferred Investment Tax Credits	**202,419.46**	**355,758.82**	**(153,339.36)**
	Regulatory Liabilities	**11,049,753.09**	**13,831,965.72**	**(2,782,212.63)**
2440002	LT Unreal Losses - Non Affil	2,925,527.91	4,200,196.07	(1,274,668.16)
2440022	L/T Liability MTM Collateral	(249,897.00)	(582,545.00)	332,648.00
2450011	L/T Liability-Commodity Hedges	701.00	82,731.00	(82,030.00)
	Long-Term Energy Trading Contracts	2,676,331.91	3,700,382.07	(1,024,050.16)
2520000	Customer Adv for Construction	80,086.36	63,177.74	16,908.62
	Customer Advances for Construction	80,086.36	63,177.74	16,908.62
	Deferred Gains on Sale/Leaseback	0.00	0.00	0.00
	Deferred Gains on Dispostion of Utility Plant	0.00	0.00	0.00
2530000	Other Deferred Credits	0.00	0.00	0.00
2530022	Customer Advance Receipts	1,602,837.78	2,634,497.53	(1,031,659.75)
2530050	Deferred Rev -Pole Attachments	296,768.25	78,940.35	217,827.90
2530067	IPP - System Upgrade Credits	265,974.64	260,279.72	5,694.92
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	158,828.00	162,614.00	(3,786.00)
2530112	Other Deferred Credits-Curr	221,616.17	1,113,326.72	(891,710.55)
2530114	Federl Mitigation Deferal(NSR)	754,941.55	754,941.55	0.00

Kentucky Power Corp Consol
Comparative Balance Sheet
August 31, 2013

Run Date: 09/11/2013 15:22

X_OPR_COS	Rpt ID: GLR2200V Layout: GLR2200V	Month End Balances	December Balances	Variance
KYP_CORP_C(	V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	2013	Last Year	$
2530137	Fbr Opt Lns-Sold-Defd Rev	107,692.22	116,729.42	(9,037.20)
	Other Deferred Credits	3,408,658.61	5,121,329.29	(1,712,670.68)
	Deferred Credits	**6,165,076.88**	**8,884,889.10**	**(2,719,812.22)**
	DEFERRED CREDITS & REGULATED LIABILITIES	**408,900,118.79**	**408,225,779.81**	**674,338.98**
	CAPITAL & LIABILITIES	**1,605,162,782.21**	**1,618,871,728.87**	**(13,708,946.65)**

Statement of Retained Earnings

	BALANCE AT BEGINNING OF YEAR	**190,818,915.56**	**171,840,462.36**	**18,978,453.21**
	Net Income (Loss)	28,319,726.18	50,978,453.21	(22,658,727.03)
	Deductions:			
	Dividend Declared On Common Stock	(18,750,000.00)	-32,000,000	13,250,000.00
	Dividend Declared On Preferred Stock	0.00	0	0.00
	Adjustment in Retained Earnings	(0.00)	0.00	(0.00)
	Total Deductions	**(18,750,000.00)**	**(32,000,000.00)**	**13,250,000.00**
	BALANCE AT END OF PERIOD (A)	**200,388,641.74**	**190,818,915.56**	**9,569,726.18**

(A) Represents The Following Balances At End Of Period

215.0	Appropriated Retained Earnings	0.00	0.00	0.00
215.1	Appr Retnd Erngs - Amrt Rsv, Fed	0.00	0.00	0.00
	Total Appropriated Retained Earnings	0.00	0.00	0.00
2160000-1	Unapprp Retained Earnings Unrestr	190,818,915.56	171,840,462.36	18,978,453.21
2160002+	Unapprp Retained Earnings Restr	0.00	0.00	0.00
210.0	Gain on Reacquired Pref Stock	0.00	0.00	0.00
	Net Income Transferred	9,569,726.18	18,978,453.21	(9,408,727.03)
	Total Unappropriated Retained Earnings	200,388,641.74	190,818,915.56	9,569,726.18
216.1	Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
418.1	Equity Earnings of Subsidiary Co	0.00	0.00	0.00
	Total Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
	Total Other Retained Earnings Accounts	(0.00)	0.00	(0.00)
	TOTAL RETAINED EARNINGS	**200,388,641.74**	**190,818,915.56**	**9,569,726.18**

FINAL 09/10/2014

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - August, 2014

GLR7210V 09/10/14 17:11

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	126,492,312.70	(2,974,454.14)	(9.12)	0.00	1,602,202,101.32
	TOTAL PRODUCTION	**1,478,684,251.88**	**126,492,312.70**	**(2,974,454.14)**	**(9.12)**	**0.00**	**1,602,202,101.32**
101/106	TRANSMISSION	503,165,571.80	14,337,534.89	(434,518.55)	0.00	0.00	517,068,588.14
101/106	DISTRIBUTION	733,776,590.81	29,176,147.69	(5,065,790.93)	0.00	0.00	757,886,947.57
	TOTAL (ACCOUNTS 101 & 106)	**2,715,626,414.49**	**170,005,995.28**	**(8,474,763.62)**	**(9.12)**	**0.00**	**2,877,157,637.03**
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	410,466.52	0.00	6,689,615.69
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**2,721,905,563.66**	**170,005,995.28**	**(8,474,763.62)**	**410,457.40**	**0.00**	**2,883,847,252.72**
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		74,873,019.66				
107000X	TRANSFERS		(127,428,182.65)				
107000X	END. BAL.		(52,555,162.99)				76,043,985.20
	TOTAL ELECTRIC UTILITY PLANT	**2,857,910,670.58**	**117,450,832.29**	**(8,474,763.62)**	**410,457.40**	**0.00**	**2,967,297,196.65**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	**5,529,435.74**	**0.00**	**0.00**	**(0.03)**	**0.00**	**5,529,435.71**

Prepared By: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee – Prop Acctg. Canton
Sources of Info: PowerPlant Reports and PS GL

Acct 107 Transfers	**(127,428,182.65)**
Acct 101/6 Additions	**170,005,995.28**
	42,577,812.63
ARO - ASH#1 Big Sandy Ash Pond 07/2014	42,577,812.63

FINAL 09/10/2014

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - August, 2014

GLR7410V

09/10/14 17:0

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	37,923,201.48	(2,974,454.14)	(1,708,332 77)	0.00	632,744,541.46
1080001/11	TRANSMISSION	161,537,795.16	5,765,767.05	(434,518 55)	(240,721.33)	0.00	166,628,322.33
1080001/11	DISTRIBUTION	192,744,660.64	16,941,256.99	(5,065,790.93)	(1,271,390 08)	0.00	203,348,736.62
1080013	PRODUCTION	(3 620,015 26)	0.00	0.00	0.00	(349,071 32)	(3,969 086 58)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698 85)	0.00	0.00	0.00	(6,130 61)	(32,829.46)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(3,985,022 18)	3,220,444.18	(9,084,830.52)
	TOTAL (108X accounts)	**941,819,616.07**	**60,630,225.52**	**(8,474,763.62)**	**(7,205,486.36)**	**2,865,242.25**	**989,634,853.86**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	912,395.91	0.00	0.00	84,795.27	11,426,542.05
1110001	TRANSMISSION	1,607,792.68	396,013.57	0.00	0.00	0.00	2,003,806.25
1110001	DISTRIBUTION	7,182,584.75	1,025,948.04	0.00	0.00	0.00	8,208,532.79
	TOTAL (111X accounts)	**19,219,728.30**	**2,334,357.52**	**0.00**	**0.00**	**84,795.27**	**21,638,881.09**
1011006	CAPITAL LEASES	1,869,467.09	0.00	0.00	0.00	211,626.01	2,081,093.10
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT	**962,908,811.46**	**62,964,583.04**	**(8,474,763.62)**	**(7,205,466.36)**	**3,161,663.53**	**1,013,354,828.05**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonuti Prop-Ownd	214,955.75	4,446.48	0.00	0.00	0.00	219,402.23
1240027	Other Property - RWIP	(3,400 00)	0.00	0.00	0.00	0.00	(3,400 00)
	TOTAL NONUTILITY PLANT	**211,555.75**	**4,446.48**	**0.00**	**0.00**	**0.00**	**216,002.23**

Prepared By: PSnVision Report GLR7410V
Reviewer: Cindy Buckbee -- Prop Acctg. Canton
Sources of Info: PowerPlant Reports and PS GL

AEP AMERICAN ELECTRIC POWER

American Electric Power
1 Riverside Plaza
Columbus, OH 43215-2373
AEP.com

October 23, 2014

Commonwealth of Kentucky
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Please find enclosed September 2014 Financial Report pages for Kentucky Power Company consisting of the following:

Income Statement:

1-9	Income Statement
1-3	Details of Operating Revenues
4-7	Operating Expenses – Functional Expenses
8-9	Detail Statement of Taxes
Balance Sheet:	
10	Balance Sheet – Assets & Other Debits
10-12	Balance Sheet – Liabilities & Other Credits
11-12	Deferred Credits
12	Statement of Retained Earnings
Utility Property:	
13-14	Electric Property & Accum Prov for Depr & Amrtz

Sincerely,

Brian J. Frantz

Brian J. Frantz
Manager –Regulated Accounting

American Electric Power

INCOME STATEMENT

GLS8016
YTD Sep 2014
10/07/2014 15:48

Layout: GLS8016

098 V2014-09-30 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

			Kentucky Power Int Consol	Kentucky Power Company - Distribution	Kentucky Power Company - Generation	Kentucky Power Company - Transmission
			GLS8016	110	117	180
			Actual	Actual	Actual	Actual
			YTD Sep 2014	YTD Sep 2014	YTD Sep 2014	YTD Sep 2014
		REVENUES				
4400001		Residential Sales-W/Space Htg	88,528,910	87,510,710	1,018,199	0
4400002		Residential Sales-W/O Space Ht	40,924,564	40,317,519	607,045	0
4400005		Residential Fuel Rev	56,889,943	56,889,943	0	0
	A	**Revenue - Residential Sales**	**186,343,416**	**184,718,172**	**1,625,244**	-
4420001		Commercial Sales	57,382,602	56,677,611	704,991	0
4420006		Sales to Pub Auth - Schools	10,249,886	10,162,973	86,913	0
4420007		Sales to Pub Auth - Ex Schools	10,691,877	10,569,920	121,957	0
4420013		Commercial Fuel Rev	33,687,338	33,687,338	0	0
	A	**Revenue - Commercial Sales**	**112,011,702**	**111,097,842**	**913,860**	-
	B	**Revenue - Industrial Sales - Affiliated**	-	-	-	-
4420002		Industrial Sales (Excl Mines)	47,439,334	46,778,212	661,122	0
4420004		Ind Sales-NonAffil(Incl Mines)	22,047,649	21,654,203	393,447	0
4420016		Industrial Fuel Rev	69,581,640	69,581,640	0	0
	A	**Revenue - Industrial Sales - NonAffiliated**	**139,068,623**	**138,014,055**	**1,054,569**	-
		Revenue - Industrial Sales	**139,068,623**	**138,014,055**	**1,054,569**	-
	A	**Revenue - Gas Products Sales**	-	-	-	-
	A	**Revenue - Gas Transportation & Storage Sales**	-	-	-	-
	B	**Revenue - Gas Transportation & Storage Sales - Affiliated**	-	-	-	-
4440000		Public Street/Highway Lighting	1,106,616	1,084,830	21,786	0
4440002		Public St & Hwy Light Fuel Rev	240,716	240,716	0	0
	A	**Revenue - Other Retail Sales**	**1,347,332**	**1,325,545**	**21,786**	-
	B	**Revenue - Other Retail Sales - Affiliated**	-	-	-	-
		Revenue - Retail Sales	**438,771,074**	**435,155,615**	**3,615,459**	-
4560043		Oth Elec Rv-Trn-Aff-Trnf Price	0	0	0	25,314,684
4561033		PJM NITS Revenue - Affiliated	16,334,523	0	0	28,507,648
4561034		PJM TO Adm. Serv Rev - Aff	0	0	0	476,872
4561035		PJM Affiliated Trans NITS Cost	(15,593,616)	0	(27,766,740)	0
4561036		PJM Affiliated Trans TO Cost	0	0	(476,872)	0
4561059		Affil PJM Trans Enhancmnt Rev	285,227	0	0	393,446
4561060		Affil PJM Trans Enhancmnt Cost	(269,030)	0	(377,249)	0
4561062		PROVISION RTO Cost - Aff	(1,318,175)	0	(1,318,175)	0
4561063		PROVISION RTO Rev Affiliated	1,957,027	0	0	1,957,027
	B	**Revenue - Transmission-Affiliated**	**1,395,957**	-	**(29,939,037)**	**56,649,677**
4470150		Transm. Rev -Dedic. Whlsl/Muni	16,372	0	(566,391)	582,763
4470206		PJM Trans loss credits-OSS	1,695,115	0	1,695,115	0
4470207		PJM transm loss charges - LSE	(13,574,514)	0	(13,574,514)	0
4470208		PJM Transm loss credits-LSE	2,021,454	0	2,021,454	0
4470209		PJM transm loss charges-OSS	(13,883,422)	0	(13,883,422)	0
4561002		RTO Formation Cost Recovery	3,496	0	(106,024)	109,519
4561003		PJM Expansion Cost Recov	61,164	0	(65,534)	126,698
4561005		PJM Point to Point Trans Svc	511,876	0	511,876	0
4561006		PJM Trans Owner Admin Rev	228,220	0	0	228,220
4561007		PJM Network Integ Trans Svc	11,561,896	0	0	11,561,896
4561019		Oth Elec Rev Trans Non Affil	43,345	0	0	43,345
4561028		PJM Pow Fac Cre Rev Whsl Cu-NA	4,619	0	0	4,619
4561029		PJM NITS Revenue Whsl Cus-NAff	2,128,686	0	0	2,128,686
4561030		PJM TO Serv Rev Whls Cus-NAff	34,952	0	0	34,952
4561058		NonAffil PJM Trans Enhncmt Rev	390,421	0	0	390,421
4561061		NAff PJM RTEP Rev for Whsl-FR	29,441	0	0	29,441
4561064		PROVISION RTO Rev WhslCus-NAf	149,816	0	0	149,816
4561065		PROVISION RTO Rev - NonAff	880,589	0	0	880,589
	A	**Revenue - Transmission-NonAffiliated**	**(7,696,474)**	-	**(23,967,439)**	**16,270,965**
		Revenue - Transmission	**(6,300,517)**	-	**(53,906,476)**	**72,920,642**
4470001		Sales for Resale - Assoc Cos	(262)	0	(262)	0
4470035		Sls for Rsl - Fuel Rev - Assoc	262	0	262	0
4470128		Sales for Res-Aff. Pool Energy	5,479,520	0	5,479,520	0
	B	**Revenue - Resale-Affiliated**	**5,479,520**	-	**5,479,520**	-
4470002		Sales for Resale - NonAssoc	3,131	0	3,131	0
4470006		Sales for Resale-Bookout Sales	12,758,170	0	12,758,170	0
4470010		Sales for Resale-Bookout Purch	(12,461,847)	0	(12,461,847)	0
4470027		Whsal/Muni/Pb Ath Fuel Rev	2,120,555	0	2,120,555	0
4470028		Sale/Resale - NA - Fuel Rev	151,564	0	151,564	0
4470033		Whsal/Muni/Pub Auth Base Rev	3,308,767	0	3,308,767	0
4470066		PWR Trding Trans Exp-NonAssoc	(84)	0	(84)	0
4470081		Financial Spark Gas - Realized	37,948	0	37,948	0
4470082		Financial Electric Realized	1,721,551	0	1,721,551	0
4470089		PJM Energy Sales Margin	110,449,861	0	110,449,861	0
4470093		PJM Implicit Congestion-LSE	(18,754,199)	0	(18,754,199)	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Sep 2014
10/07/2014 15:46

Layout: GLS8016

09B V2014-09-30		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Sep 2014	Kentucky Power Company - Distribution 110 Actual YTD Sep 2014	Kentucky Power Company - Generation 117 Actual YTD Sep 2014	Kentucky Power Company - Transmission 180 Actual YTD Sep 2014
4470098		PJM Oper Reserve Rev-OSS	(2,963,832)	0	(2,963,832)	0
4470099		Capacity Cr Net Sales	432,564	0	432,564	0
4470100		PJM FTR Revenue-OSS	807,303	0	807,303	0
4470101		PJM FTR Revenue-LSE	8,824,172	0	8,824,172	0
4470103		PJM Energy Sales Cost	139,320,427	0	139,320,427	0
4470106		PJM Pt2Pt Trans.Purch-NonAff.	(27)	0	(27)	0
4470107		PJM NITS Purch-NonAff	13,477	0	13,477	0
4470109		PJM FTR Revenue-Spec	(53,406)	0	(53,406)	0
4470110		PJM TO Admin. Exp.-NonAff	35,331	0	35,331	0
4470112		Non-Trading Bookout Sales-OSS	4,943	0	4,943	0
4470115		PJM Meter Corrections-OSS	(17,491)	0	(17,491)	0
4470116		PJM Meter Corrections-LSE	23,677	0	23,677	0
4470124		PJM Incremental Spot-OSS	1	0	1	0
4470126		PJM Incremental Imp Cong-OSS	(27,961,999)	0	(27,961,999)	0
4470141		PJM Contract Net Charge Credit	(14)	0	(14)	0
4470143		Financial Hedge Realized	2,197,413	0	2,197,413	0
4470144		Realiz.Sharing - 06 SIA	69	0	69	0
4470155		OSS Physical Margin Reclass	175	0	175	0
4470156		OSS Optim. Margin Reclass	(175)	0	(175)	0
4470168		Interest Rate Swaps-Power	(13,559)	0	(13,559)	0
4470170		Non-ECR Auction Sales-OSS	1,385,398	0	1,385,398	0
4470174		PJM Whlse FTR Rev - OSS	81	0	81	0
4470175		OSS Sharing Reclass - Retail	275,336	0	275,336	0
4470176		OSS Sharing Reclass-Reduction	(275,336)	0	(275,336)	0
4470180		Trading intra-book Reclass	(119,770)	0	(119,770)	0
4470181		Auction intra-book Reclass	119,770	0	119,770	0
4470202		PJM OpRes-LSE-Credit	657,210	0	657,210	0
4470203		PJM OpRes-LSE-Charge	(4,789,252)	0	(4,762,894)	(26,358)
4470204		PJM Spinning-Credit	(0)	0	(0)	0
4470214		PJM 30m Suppl Reserve CR OSS	28,208	0	28,208	0
4470220		PJM Regulation - OSS	182,167	0	182,167	0
4470221		PJM Spinning Reserve - OSS	10,260	0	10,260	0
4470222		PJM Reactive - OSS	461,059	0	461,059	0
4560050		Oth Elec Rev-Coal Trd Rlzd G-L	(10,448)	0	(10,448)	0
5550080		PJM Hourly Net Purch -FERC	(28,696,354)	0	(28,696,354)	0
5550094		Purchased Power - Fuel	1,305	0	1,305	0
	A	**Revenue - Resale-NonAffiliated**	**189,214,099**	-	**189,240,457**	**(26,358)**
	A	**Revenue - Resale-Realized**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt MTM**	-	-	-	-
	A	**Revenue - Resale-Risk Mgmt Activities**	-	-	-	-
		Revenue - Sales for Resale	**194,693,619**	-	**194,719,977**	**(26,358)**
4470074		Sale for Resale-Aff-Trnf Price	0	0	326,148,151	0
4540001		Rent From Elect Property - Af	195,561	583,036	0	0
4560001		Oth Elect Rev - Affiliated	22,774	0	22,774	0
	B	**Revenue - Other Ele-Affiliated**	**218,335**	**583,036**	**326,170,925**	-
4500000		Forfeited Discounts	2,881,701	2,881,701	0	0
4510001		Misc Service Rev - Nonaffil	296,785	286,618	0	10,167
4540002		Rent From Elect Property-NAC	62,789	1,800	57,489	3,500
4540005		Rent from Elec Prop-Pole Attch	3,525,616	3,525,616	0	0
4560007		Oth Elect Rev - DSM Program	3,965,693	3,965,693	0	0
		Revenue - Other Ele-NonAffiliated	**10,732,584**	**10,661,428**	**57,489**	**13,667**
		Revenue - Gas	-	-	-	-
4118002		Comp. Allow Gains Title IV SO2	383	0	383	0
4118004		Comp. Allow. Gains-Ann NOx	8,533	0	8,533	0
		Gain/(Loss) on Allowances	**8,916**	-	**8,916**	-
	A	**Revenue - Other Ele-NonAffiliated**	**10,741,500**	**10,661,428**	**66,405**	**13,667**
		Revenue - Other Opr Electric	**10,959,835**	**11,244,464**	**326,237,330**	**13,667**
	D	**Revenue Merchandising & Contract Work**	-	-	-	-
	C	**Revenues Non-Utility Operations - Affiliated**	-	-	-	-
	D	**Revenues Non-Utility Operations - NonAffiliated**	-	-	-	-
		Revenues from Non-Utility Operations	-	-	-	-
	C	**Non-Operating Rental Income - Affiliated**	-	-	-	-
4180001		Non-Operatng Rental Income	24,400	23,500	900	0
4180003		Non-Opratng Rntal Inc-Maint	(16)	0	(16)	0
4180005		Non-Opratng Rntal Inc-Depr	(5,002)	0	0	(5,002)
	D	**Non-Operating Rental Income - NonAffiliated**	**19,382**	**23,500**	**884**	**(5,002)**
		Non-Operating Rental Income	**19,382**	**23,500**	**884**	**(5,002)**
	C	**Non-Operating Misc Income -Affiliated**	-	-	-	-
4210002		Misc Non-Op Inc-NonAsc-Rents	1,585	527	628	430

American Electric Power

INCOME STATEMENT

GLS8016
YTD Sep 2014
10/07/2014 15:48

Layout: GLS8016

09B V2014-09-30		Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Sep 2014	Kentucky Power Company - Distribution 110 Actual YTD Sep 2014	Kentucky Power Company - Generation 117 Actual YTD Sep 2014	Kentucky Power Company - Transmission 180 Actual YTD Sep 2014
4210007		Misc Non-Op Inc - NonAsc - Oth	180,604	588	180,016	0
	D	**Non-Operating Misc Income - NonAffiliated**	**182,189**	**1,115**	**180,644**	**430**
		Non-Operating Misc Income	**182,189**	**1,115**	**180,644**	**430**
4540004		Rent From Elect Prop-ABD-Nonaf	67,199	67,199	0	0
4560015		Other Electric Revenues - ABD	201,050	165,873	0	35,177
	D	**Associated Business Development Income**	**268,250**	**233,073**	**-**	**35,177**
		Revenue - Other Opr - Other	**469,821**	**257,688**	**181,528**	**30,605**
	=(C)	***Memo: Revenue-Oth Opr-Oth Aff***	-	-	-	-
	=(D)	***Memo: Revenue-Oth Opr-Oth Non***	***469,821***	***257,688***	***181,528***	***30,605***
		Revenue - Other Operating	**11,429,655**	**11,502,152**	**326,418,858**	**44,272**
	A	**Provision for Rate Refund - NonAffiliated**	-	-	-	-
	B	**Provision for Rate Refund - Affiliated**	-	-	-	-
		Provision for Rate Refund	-	-	-	-
4210031		Pwr Sales Outside Svc Terrtry	181,875	0	181,875	0
4210032		Pwr Purch Outside Svc Terrtry	(555)	0	(555)	0
	A	**Revenue - Power Sales**	**181,320**	**-**	**181,320**	**-**
		TOTAL OPERATING REVENUES	**638,775,150**	**446,657,766**	**471,029,138**	**72,938,556**
=(A)		*Memo: G/T/D Revenue*	*631,211,518*	*445,817,042*	*169,136,202*	*16,258,274*
=(B)		*Memo: Other Affiliated Revenue*	*7,093,811*	*583,036*	*301,711,408*	*56,649,677*
=(C)		*Memo: Revenue-Oth Opr-Oth Aff*	-	-	-	-
=(D)		*Memo: Revenue-Oth Opr-Oth Non*	*469,821*	*257,688*	*181,528*	*30,605*
		Memo: Total Operating Revenues	*638,775,150*	*446,657,766*	*471,029,138*	*72,938,556*
=(E)=(B)+(C)		*Memo: Affiliated Revenue*	***7,093,811***	***583,036***	***301,711,408***	***56,649,677***
=(F)=(D)+(A)		*Memo: Non-Affiliated Revenue*	***631,681,339***	***446,074,730***	***169,317,730***	***16,288,879***
		Memo: Total Operating Revenues	***638,775,150***	***446,657,766***	***471,029,138***	***72,938,556***
		FUEL EXPENSES				
5010000		Fuel	1,430,996	0	1,430,996	0
5010001		Fuel Consumed	212,076,995	0	212,076,995	0
5010003		Fuel - Procure Unload & Handle	8,689,227	0	8,689,227	0
5010012		Ash Sales Proceeds	(10,817)	0	(10,817)	0
5010013		Fuel Survey Activity	(77,282)	0	(77,282)	0
5010019		Fuel Oil Consumed	4,835,156	0	4,835,156	0
5010027		Gypsum handling/disposal costs	325,319	0	325,319	0
5010028		Gypsum Sales Proceeds	(563,042)	0	(563,042)	0
		Fuel Expense Total	**226,706,553**	**-**	**226,706,553**	**-**
5010005		Fuel - Deferred	(11,840,727)	0	(11,840,727)	0
		Deferred Fuel Expense	**(11,840,727)**	**-**	**(11,840,727)**	**-**
		Over Under Fuel Expense				
		Fuel for Electric Generation	**214,865,826**	**-**	**214,865,826**	**-**
5010029		Gypsum handling/displ-Affiliat	138,375	0	138,375	0
		Fuel from Affiliates for Electric Generation	**138,375**	**-**	**138,375**	**-**
5090000		Allow Consum Title IV SO2	7,000,454	0	7,000,454	0
5090001		Allowance Consumption - NOx	33,844	0	33,844	0
5090005		An NOx Cons Exp	102,874	0	102,874	0
		Allowances - Consumption	**7,137,172**	**-**	**7,137,172**	**-**
5020002		Urea Expense	4,051,812	0	4,051,812	0
5020003		Trona Expense	266,030	0	266,030	0
5020004		Limestone Expense	3,011,044	0	3,011,044	0
5020005		Polymer expense	68,696	0	68,696	0
5020007		Lime Hydrate Expense	13,540	0	13,540	0
		Emissions Control - Chemicals	**7,411,122**	**-**	**7,411,122**	**-**
		Total Fuel for Electric Generation	**229,552,495**	**-**	**229,552,495**	**-**
		Memo: NonAff Fuel/Allow/Emissions	***229,414,120***	**-**	***229,414,120***	**-**
5550004		Purchased Power-Pool Capacity	181,949	0	181,949	0
5550005		Purchased Power - Pool Energy	676,093	0	676,093	0
5550027		Purch Pwr-Non-Fuel Portion-Aff	37,221,397	0	37,221,397	0
5550029		Purch Power-Assoc-Trnsfr Price	0	326,146,151	0	0
5550046		Purch Power-Fuel Portion-Affil	49,423,531	0	49,423,531	0
5550101		Purch Power-Pool Non-Fuel -Aff	168,508	0	168,508	0
5550102		Pur Power-Pool NonFuel-OSS-Aff	214,985	0	214,985	0
		Purchased Electricity from AEP - Affiliates	**87,886,463**	**326,146,151**	**87,886,463**	**-**
5550000		Purchased Power	273	0	270	3
5550001		Purch Pwr-NonTrading-Nonassoc	440,550	0	440,550	0
5550032		Gas-Conversion-Mone Plant	13,874	0	13,874	0
5550039		PJM Inadvertent Mtr Res-OSS	(58,182)	0	(58,182)	0
5550040		PJM Inadvertent Mtr Res-LSE	(25,854)	0	(25,854)	0
5550041		PJM Ancillary Serv -Sync	5,661	0	5,661	0
5550074		PJM Reactive-Charge	(11,826)	0	(11,826)	0

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American Electric Power

INCOME STATEMENT

GLS8016
YTD Sep 2014
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Layout: GLS8016
09B V2014-09-30 Account: GL_ACCT_SEC Business Units: SEGMENT_CONS

Account	Description	Kentucky Power Int Consol GLS8016 Actual YTD Sep 2014	Kentucky Power Company - Distribution 110 Actual YTD Sep 2014	Kentucky Power Company - Generation 117 Actual YTD Sep 2014	Kentucky Power Company - Transmission 180 Actual YTD Sep 2014
5550076	PJM Black Start-Charge	1,226,353	0	1,226,353	0
5550077	PJM Black Start-Credit	(7)	0	(7)	0
5550078	PJM Regulation-Charge	1,689,301	0	1,689,301	0
5550079	PJM Regulation-Credit	(413,590)	0	(413,590)	0
5550083	PJM Spinning Reserve-Charge	1,347,829	0	1,347,829	0
5550084	PJM Spinning Reserve-Credit	(323,380)	0	(323,380)	0
5550090	PJM 30m Suppl Rserv Charge LSE	386,657	0	386,657	0
5550093	Peak Hour Avail charge - LSE	(67,133)	0	(67,133)	0
5550099	PJM Purchases-non-ECR-Auction	1,451,310	0	1,451,310	0
5550100	Capacity Purchases-Auction	61,814	0	61,614	0
5550107	Capacity purchases - Trading	219,363	0	219,363	0
	Purchased Electricity for Resale - NonAffiliated	**5,942,813**	-	**5,942,810**	**3**
	Purchased Gas for Resale - Affiliated	-	-	-	-
	Purchased Gas for Resale - NonAffiliated	-	-	-	-
	Total Purchased Power	**93,829,276**	**326,148,151**	**93,829,273**	**3**
	GROSS MARGIN	**315,383,379**	**120,509,816**	**147,647,370**	**72,938,553**
	OPERATING EXPENSES				
5000000	Oper Supervision & Engineering	2,816,198	0	2,816,198	0
5000001	Oper Super & Eng-RATA-Affil	52,712	0	52,712	0
5020000	Steam Expenses	1,850,356	0	1,850,356	0
5050000	Electric Expenses	406,113	0	406,113	0
5060000	Misc Steam Power Expenses	5,678,999	0	5,678,999	0
5060002	Misc Steam Power Exp-Assoc	43,342	0	43,342	0
5060003	Removal Cost Expense - Steam	(74,926)	0	(74,926)	0
5060004	NSR Settlement Expense	(7,679)	0	(7,679)	0
5060025	Misc Stm Pwr Exp Environmental	(11)	0	(11)	0
	Steam Generation Op Exp	**10,765,103**	-	**10,765,103**	-
	Nuclear Generation Op Exp	-	-	-	-
	Hydro Generation Op Exp	-	-	-	-
5560000	Sys Control & Load Dispatching	366,474	(1)	366,410	65
5570000	Other Expenses	1,276,778	614	1,275,822	342
5570007	Other Pwr Exp - Wholesale RECs	12,054	12,054	0	0
5570008	Other Pwr Exp - Voluntary RECs	70	70	0	0
5757000	PJM Admin-MAM&SC- OSS	436,556	0	436,556	0
5757001	PJM Admin-MAM&SC- Internal	544,003	0	544,003	(0)
	Other Generation Op Exp	**2,635,935**	**12,737**	**2,622,790**	**407**
5600000	Oper Supervision & Engineering	845,718	3,917	6,403	835,398
5611000	Load Dispatch - Reliability	6,000	0	0	6,000
5612000	Load Dispatch-Mntr&Op TransSys	631,371	56	93	631,221
5614000	PJM Admin-SSC&DS-OSS	404,311	0	404,311	0
5614001	PJM Admin-SSC&DS-Internal	491,877	0	491,877	0
5614007	RTO Admin Default LSE	3,874	0	3,539	335
5614008	PJM Admin Defaults OSS	2,417	0	2,417	0
5615000	Reliability,Plng&Stds Develop	76,878	5,672	9,183	62,024
5618000	PJM Admin-RP&SDS-OSS	96,721	0	96,721	0
5618001	PJM Admin-RP&SDS- Internal	116,874	0	116,874	0
5620001	Station Expenses - Nonassoc	281,308	5,460	0	275,849
5630000	Overhead Line Expenses	120,214	21	0	120,193
5650002	Transmssn Elec by Others-NAC	134,058	0	134,058	0
5650007	Tran Elec by Oth-Aff-Trn Pnce	0	25,314,684	0	0
5650012	PJM Trans Enhancement Charge	3,151,033	0	3,151,033	0
5650015	PJM TO Serv Exp - Aff	28,506	0	28,506	0
5650016	PJM NITS Expense - Affiliated	4,164,557	0	4,164,557	0
5650019	Affil PJM Trans Enhncement Exp	306,511	0	306,511	0
5650020	PROVISION RTO Affl Expense	899,183	0	899,183	0
5660000	Misc Transmission Expenses	958,168	6,946	9,679	941,542
5670001	Rents - Nonassociated	250	0	0	250
5670002	Rents - Associated	0	0	0	387,475
5757002	SPP Admin-MAM&SC	0	0	0	0
	Transmission Op Exp	**12,719,831**	**25,336,756**	**9,824,947**	**3,260,287**
5800000	Oper Supervision & Engineering	489,540	478,095	4,123	7,322
5810000	Load Dispatching	2,969	2,210	0	759
5820000	Station Expenses	150,589	145,174	0	5,415
5830000	Overhead Line Expenses	751,794	751,820	(135)	109
5840000	Underground Line Expenses	79,664	79,492	126	46
5841000	Oper of Energy Storage Equip	0	0	0	0
5850000	Street Lighting & Signal Sys E	120,282	120,282	0	0
5860000	Meter Expenses	562,189	560,742	1,009	439

American Electric Power

INCOME STATEMENT

GLS8016
YTD Sep 2014
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Layout: GLS8016

09B V2014-09-30	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Sep 2014	Kentucky Power Company - Distribution 110 Actual YTD Sep 2014	Kentucky Power Company - Generation 117 Actual YTD Sep 2014	Kentucky Power Company - Transmission 180 Actual YTD Sep 2014
5870000	Customer Installations Exp	152,245	152,245	0	0
5880000	Miscellaneous Distribution Exp	2,768,272	2,739,079	7,108	22,084
5890001	Rents - Nonassociated	1,254,829	1,254,829	0	0
5890002	Rents - Associated	51,597	51,597	0	0
	Distribution Op Exp	**6,383,970**	**6,335,564**	**12,230**	**36,175**
9010000	Supervision - Customer Accts	217,429	217,355	54	20
9020000	Meter Reading Expenses	10,660	10,272	282	106
9020001	Customer Card Reading	325	97	167	61
9020002	Meter Reading - Regular	329,091	329,091	0	0
9020003	Meter Reading - Large Power	40,790	40,790	0	0
9020004	Read-In & Read-Out Meters	43,140	43,140	0	0
9030000	Cust Records & Collection Exp	251,922	247,145	368	4,410
9030001	Customer Orders & Inquiries	1,798,707	1,797,688	769	251
9030002	Manual Billing	29,109	28,213	5	892
9030003	Postage - Customer Bills	600,207	600,207	0	0
9030004	Cashiering	104,382	103,550	434	398
9030005	Collection Agents Fees & Exp	50,299	50,299	0	0
9030006	Credit & Oth Collection Activi	556,343	556,295	36	12
9030007	Collectors	431,813	431,813	0	0
9030009	Data Processing	122,739	122,726	9	3
9040007	Uncoll Accts - Misc Receivable	(56,466)	(56,466)	0	0
9050000	Misc Customer Accounts Exp	19,786	19,786	0	0
9070000	Supervision - Customer Service	113,222	113,216	3	3
9070001	Supervision - DSM	(11)	(4)	(4)	(3)
9080000	Customer Assistance Expenses	361,504	361,490	7	7
9080001	DSM-Customer Advisory Grp	924	924	0	0
9080009	Cust Assistance Expense - DSM	3,323,958	3,323,169	569	220
9090000	Information & Instruct Advrts	68,723	20,862	34,816	13,045
9100000	Misc Cust Svc&Informational Ex	35,423	14,667	15,259	5,496
	Customer Service and Information Op Exp	**8,454,018**	**8,376,323**	**52,774**	**24,921**
9120000	Demonstrating & Selling Exp	20,855	20,855	0	0
9120003	Demo & Selling Exp - Area Dev	(321)	(321)	0	0
	Sales Expenses	**20,534**	**20,534**	-	-
	Memo: Insurance (9240 9250)	**1,330,019**	**657,170**	**486,976**	**185,873**
9200000	Administrative & Gen Salaries	6,822,939	3,035,431	2,801,382	986,127
9210001	Off Supl & Exp - Nonassociated	543,558	325,210	165,953	52,396
9210003	Office Supplies & Exp - Trnsf	12	7	4	1
9220000	Administrative Exp Trnsf - Cr	(457,259)	(457,259)	0	(0)
9220001	Admin Exp Trnsf to Cnstrctn	(349,357)	(349,357)	0	0
9220004	Admin Exp Trnsf to ABD	(2,395)	(1,011)	0	(1,384)
9230001	Outside Svcs Empl - Nonassoc	1,122,680	495,870	477,561	149,249
9230002	Outside Svcs Empl - Assoc	(0)	(0)	(0)	0
9230003	AEPSC Billed to Client Co	186,685	61,677	99,411	25,597
9240000	Property Insurance	395,947	125,690	125,024	145,233
9250000	Injuries and Damages	907,403	626,289	239,258	41,857
9250001	Safety Dinners and Awards	3,126	1,403	1,375	349
9250002	Emp Accdent Prvntion-Adm Exp	7,512	4,828	1,924	760
9250004	Injuries to Employees	2,949	0	2,949	0
9250006	Wrkrs Cmpnstn Pre&Slf Ins Prv	41,439	(19,402)	51,768	9,074
9250007	Prsnal Injries&Prop Dmage-Pub	69,841	3,058	66,751	32
9250010	Frg Ben Loading - Workers Comp	(98,199)	(84,696)	(2,072)	(11,431)
9260000	Employee Pensions & Benefits	3,452	3,452	0	0
9260001	Edit & Print Empl Pub-Salaries	19,703	7,109	8,117	4,477
9260002	Pension & Group Ins Admin	32,538	15,684	15,325	1,529
9260003	Pension Plan	3,802,673	1,720,210	1,877,259	205,205
9260004	Group Life Insurance Premiums	110,898	44,426	59,049	7,423
9260005	Group Medical Ins Premiums	3,825,129	1,890,613	1,645,100	289,417
9260006	Physical Examinations	1	0	0	1
9260007	Group L-T Disability Ins Prem	13,619	8,968	3,989	662
9260009	Group Dental Insurance Prem	142,978	73,130	60,397	9,450
9260010	Training Administration Exp	455	198	202	55
9260012	Employee Activities	4,532	3,231	685	616
9260014	Educational Assistance Pmts	1,438	900	455	83
9260019	Employee Benefit Exp - COLI	10,000	0	10,000	0
9260021	Postretirement Benefits - OPEB	(2,744,652)	(1,308,483)	(1,254,200)	(181,969)
9260027	Savings Plan Contributions	1,585,600	698,366	809,242	77,991
9260036	Deferred Compensation	4,504	4,504	0	0
9260037	Supplemental Pension	179	179	0	0
9260040	SFAS 112 Postemployment Benef	433,979	0	433,979	0
9260050	Frg Ben Loading - Pension	(1,136,730)	(795,261)	(264,329)	(77,140)

American Electric Power

INCOME STATEMENT

GLS8016
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Layout: GLS8018

09B V2014-09-30	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Sep 2014	Kentucky Power Company - Distribution 110 Actual YTD Sep 2014	Kentucky Power Company - Generation 117 Actual YTD Sep 2014	Kentucky Power Company - Transmission 180 Actual YTD Sep 2014
9260051	Frg Ben Loading - Grp Ins	(1,345,126)	(928,472)	(304,760)	(111,895)
9260052	Frg Ben Loading - Savings	(521,234)	(322,656)	(156,838)	(41,940)
9260053	Frg Ben Loading - OPEB	391,462	318,946	31,087	41,429
9260055	IntercoFringeOffset- Don't Use	(1,292,479)	(273,401)	(878,215)	(140,863)
9260057	Postret Ben Medicare Subsidy	461,856	186,892	257,233	17,731
9260058	Frg Ben Loading - Accrual	(112,988)	(53,903)	(53,602)	(5,483)
9260060	Amort-Post Retirement Benefit	162,465	97,186	53,405	11,874
9270000	Franchise Requirements	106,590	106,590	0	0
9280000	Regulatory Commission Exp	24,857	8,918	10,211	5,728
9280001	Regulatory Commission Exp-Adm	0	0	0	0
9280002	Regulatory Commission Exp-Case	140,493	34,358	84,990	21,145
9301000	General Advertising Expenses	848	298	362	187
9301001	Newspaper Advertising Space	9,643	3,473	4,007	2,163
9301002	Radio Station Advertising Time	4,445	1,606	1,838	999
9301010	Publicity	2,492	894	1,059	538
9301012	Public Opinion Surveys	33,695	33,692	0	4
9301015	Other Corporate Comm Exp	10,028	7,103	1,980	945
9302000	Misc General Expenses	158,852	80,180	44,384	34,287
9302003	Corporate & Fiscal Expenses	21,379	5,000	15,173	1,207
9302004	Research, Develop&Demonstr Exp	3,483	3,483	0	0
9302458	AEPSC Non Affiliated expenses	(0)	0	(0)	0
9310001	Rents - Real Property	82,806	82,806	0	0
9310002	Rents - Personal Property	197,445	133,519	55,324	8,602
	Administration & General	**13,848,190**	**5,661,482**	**6,604,394**	**1,582,314**
4111005	Accretion Expense	728,946	0	728,946	0
	Accretion	**728,946**	-	**728,946**	-
4116000	Gain From Disposition of Plant	(3,015)	(3,015)	0	0
	Loss/(Gain) on Utility Plant	**(3,015)**	**(3,015)**	-	-
9302006	Assoc Bus Dev - Materials Sold	34,853	34,853	0	0
9302007	Assoc Business Development Exp	63,910	37,592	61	26,257
	Associated Business Development Expenses	**98,763**	**72,445**	**61**	**26,257**
	Gain on Disposition of Property	-	-	-	-
	Loss on Disposition of Property	-	-	-	-
	Loss(Gain) of Sale of Property	-	-	-	-
4010001	Operation Exp - Nonassociated	(0)	0	(0)	0
4265009	Factored Cust A/R Exp - Affil	712,054	712,054	0	0
4265010	Fact Cust A/R-Bad Debts-Affil	1,356,445	1,356,445	0	0
	Opr Exp and Factored A/R	**2,068,499**	**2,068,499**	**(0)**	-
	Water Heaters	-	-	-	-
4265004	Social & Service Club Dues	53,011	18,261	23,896	10,854
4265007	Regulatory Expenses	2,879	1,028	1,204	646
	Expense of Non-Utility Operation	**55,890**	**19,290**	**25,100**	**11,501**
4210009	Misc Non-Op Exp - NonAssoc	5,791	1,601	3,184	1,006
	Misc NonOp Expenses - NonAssoc	**5,791**	**1,601**	**3,184**	**1,006**
4261000	Donations	306,768	217,521	76,006	13,241
	Donation Contributions	**306,768**	**217,521**	**76,006**	**13,241**
4263001	Penalties	62,248	23,973	24,194	14,081
	Provision for Penalties	**62,248**	**23,973**	**24,194**	**14,081**
4264000	Civic & Political Activities	202,116	74,698	80,298	47,120
	Civic & Political Activities	**202,116**	**74,698**	**80,298**	**47,120**
4265002	Other Deductions - Nonassoc	1,320	455	578	287
4265033	Transition Costs	5,267	0	5,267	0
	Other Deductions	**6,586**	**455**	**5,845**	**287**
	Shutdown Coal Company Expenses	-	-	-	-
	All Other Operational Expenses	**2,707,899**	**2,406,037**	**214,627**	**87,235**
	Operational Expenses	**5[illegible],360,172**	**48,218,864**	**30,825,872**	**5,017,596**
5100000	Maint Supv & Engineering	2,813,997	0	2,813,997	0
5110000	Maintenance of Structures	1,231,472	0	1,231,472	0
5120000	Maintenance of Boiler Plant	12,099,934	0	12,099,934	0
5130000	Maintenance of Electric Plant	2,222,884	0	2,222,884	0
5140000	Maintenance of Misc Steam Plt	1,086,928	0	1,086,928	0
	Steam Generation Maintenance	**19,455,215**	-	**19,455,215**	-
	Nuclear Generation Maintenance	-	-	-	-
	Hydro Generation Maintenance	-	-	-	-
	Other Generation Maintenance	-	-	-	-
5680000	Maint Supv & Engineering	62,136	17	0	62,119
5690000	Maintenance of Structures	5,628	0	0	5,628
5691000	Maint of Computer Hardware	13,713	13	9	13,691
5692000	Maint of Computer Software	191,643	3,672	0	187,971

American Electric Power

INCOME STATEMENT

GLS8016
YTD Sep 2014
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Layout: GLS8016

09B V2014-09-30	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Sep 2014	Kentucky Power Company - Distribution 110 Actual YTD Sep 2014	Kentucky Power Company - Generation 117 Actual YTD Sep 2014	Kentucky Power Company - Transmission 180 Actual YTD Sep 2014
5693000	Maint of Communication Equip	12,921	0	0	12,921
5700000	Maint of Station Equipment	554,543	18,215	1	536,328
5710000	Maintenance of Overhead Lines	2,369,264	(1,519)	66	2,370,717
5720000	Maint of Underground Lines	208	0	0	208
5730000	Maint of Misc Trnsmssion Plt	171,356	25	41	171,291
	Transmission Maintenance	**3,381,412**	**20,422**	**117**	**3,360,873**
5900000	Maint Supv & Engineering	1,771	1,734	(1)	38
5910000	Maintenance of Structures	8,941	8,319	0	623
5920000	Maint of Station Equipment	569,444	548,807	50	20,587
5930000	Maintenance of Overhead Lines	23,702,197	23,702,815	2,576	(3,194)
5930001	Tree and Brush Control	264,586	264,586	0	0
5930006	Maint Ovh Lines Strm Exp-OvUnd	1,292	1,292	0	0
5930010	Storm Expense Amortization	3,523,833	3,523,833	0	0
5940000	Maint of Underground Lines	68,256	68,256	0	0
5950000	Maint of Lne Trnf Rglators&Dvi	49,125	49,125	0	0
5960000	Maint of Strt Lghtng & Sgnal S	41,540	41,540	0	0
5970000	Maintenance of Meters	59,539	56,642	0	2,897
5980000	Maint of Misc Distribution Plt	133,944	132,941	0	1,003
	Distribution Maintenance	**28,424,469**	**28,399,890**	**2,626**	**21,953**
9350000	Maintenance of General Plant	149	0	0	149
9350001	Maint of Structures - Owned	211,934	209,621	15	2,299
9350002	Maint of Structures - Leased	43,088	41,423	1,078	586
9350003	Maint of Prprty Held Fture Use	451	(1)	454	(1)
9350006	Maint of Carrier Equipment	13	13	0	0
9350012	Maint of Data Equipment	346	0	346	0
9350013	Maint of Cmmncation Eq-Unall	509,845	466,155	43,690	0
9350015	Maint of Office Furniture & Eq	406,445	213,506	192,939	0
9350016	Maintenance of Video Equipment	120	120	0	0
9350019	Maint of Gen Plant-SCADA Equ	363	360	2	0
9350023	Site Communications Services	286	0	286	0
9350024	Maint of DA-AMI Comm Equip	13,963	13,963	0	0
	Administration & General Maintenance	**1,187,003**	**945,160**	**238,810**	**3,032**
	All Other Maintenance Expenses	-	-	-	-
	Maintenance Expenses	**52,448,098**	**29,365,472**	**19,696,767**	**3,385,859**
	Total Operational and Maintenance Expenses	**110,808,271**	**77,584,336**	**50,522,838**	**8,403,455**
4040001	Amort. of Plant	2,646,631	1,160,416	1,036,456	449,759
4060001	Amort of Plt Acq Adj	28,962	0	0	28,962
	DDA Amortization	**2,675,593**	**1,160,416**	**1,036,456**	**478,721**
4073000	Regulatory Debits	216,815	0	0	216,815
	DDA Regulatory Debits	**216,815**	-	-	**216,815**
	DDA Regulatory Credits	-	-	-	-
	Amortization	**2,892,408**	**1,160,416**	**1,036,456**	**695,536**
4030001	Depreciation Exp	67,465,273	19,122,206	41,830,565	6,512,502
	DDA Depreciation	**67,465,273**	**19,122,206**	**41,830,565**	**6,512,502**
	DDA STP Nuclear Decommissioning	-	-	-	-
4031001	Depr - Asset Retirement Oblig	365,154	0	365,154	0
	DDA Asset Retirement Obligation	**365,154**	-	**365,154**	-
	DDA Removal Costs	-	-	-	-
	Depreciation	**67,830,427**	**19,122,206**	**42,195,719**	**6,512,502**
	Depreciation and Amortization	**70,722,835**	**20,282,622**	**43,232,175**	**7,208,038**
	Franchise Taxes	-	-	-	-
408100613	State Gross Receipts Tax	(5,942)	1	(5,943)	0
408100614	State Gross Receipts Tax	38,930	2	38,928	0
	Revenue-kWhr Taxes	**32,988**	**3**	**32,985**	-
4081002	FICA	2,945,761	1,273,502	1,520,293	151,966
4081003	Federal Unemployment Tax	18,423	7,964	9,491	969
4081007	State Unemployment Tax	66,379	25,187	38,014	3,179
4081033	Fringe Benefit Loading - FICA	(929,226)	(573,751)	(278,701)	(76,774)
4081034	Fringe Benefit Loading - FUT	(6,772)	(3,929)	(2,437)	(407)
4081035	Fringe Benefit Loading - SUT	(18,345)	(8,872)	(8,550)	(923)
	Payroll Taxes	**2,076,220**	**720,102**	**1,278,109**	**78,009**
408102014	State Business Occup Taxes	2,979,428	0	2,979,428	0
	Capacity Taxes	**2,979,428**	-	**2,979,428**	-
408100509	Real & Personal Property Taxes	3,975	3,907	0	69
408100510	Real Personal Property Taxes	131	131	0	0
408100512	Real Personal Property Taxes	1,586,369	111,154	1,447,634	27,581
408100513	Real Personal Property Taxes	8,323,166	4,494,933	1,326,323	2,501,910
408102910	Real Pers Prop Tax-Cap Leases	12	12	0	0

American Electric Power

INCOME STATEMENT

GLS8016
YTD Sep 2014
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Layout: GLS8016

08B V2014-09-30	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Sep 2014	Kentucky Power Company - Distribution 110 Actual YTD Sep 2014	Kentucky Power Company - Generation 117 Actual YTD Sep 2014	Kentucky Power Company - Transmission 180 Actual YTD Sep 2014
408102913	Real-Pers Prop Tax-Cap Leases	2,945	790	1,974	180
408102914	Real-Pers Prop Tax-Cap Leases	16,621	12,168	1,438	3,015
408103613	Real Prop Tax-Cap Leases	(1,473)	(1,473)	0	0
408103614	Real Prop Tax-Cap Leases	19,125	19,125	0	0
408200513	Real Personal Property Taxes	44,652	7,254	2,199	35,199
	Property Taxes	**9,995,522**	**4,648,000**	**2,779,568**	**2,567,954**
408101813	St Publ Serv Comm Tax-Fees	473,122	473,122	0	0
408101814	St Publ Serv Comm Tax-Fees	267,388	267,388	0	0
	Regulatory Fees	**740,510**	**740,510**	-	-
408101414	Federal Excise Taxes	3,744	0	3,744	0
	Production Taxes	**3,744**	-	**3,744**	-
408101714	St Lic Rgstrtion Tax-Fees	240	240	0	0
408101900	State Sales and Use Taxes	(342,470)	(156,655)	(178,775)	(7,040)
408101912	State Sales and Use Taxes	218,039	89,065	119,078	9,896
408101913	State Sales and Use Taxes	1,295	1,295	0	0
408101914	State Sales and Use Taxes	12,550	12,550	0	0
408102214	Municipal License Fees	445	445	0	0
	Miscellaneous Taxes	**(109,901)**	**(53,060)**	**(59,697)**	**2,856**
	Other Non-Income Taxes	**(106,157)**	**(53,060)**	**(55,953)**	**2,856**
	Taxes Other Than Income Taxes	**18,718,512**	**6,055,555**	**7,014,137**	**2,648,820**
	TOTAL OPERATING EXPENSES	**197,249,617**	**103,922,513**	**100,768,950**	**18,260,313**
	Memo: SEC Total Operating Expenses	**520,631,388**	**430,070,664**	**424,150,718**	**18,260,316**
	OPERATING INCOME	**118,143,762**	**16,587,102**	**46,876,420**	**54,678,240**
	NON-OPERATING INCOME / (EXPENSES)				
4190002	Int & Dividend Inc - Nonassoc	109,250	48,490	56,799	3,961
	Interest & Dividend NonAffiliated	**109,250**	**48,490**	**56,799**	**3,961**
4190001	Interest Inc - Assoc Non CBP	14,193	14,193	0	0
4190005	Interest Income - Assoc CBP	44,807	(11,642)	(46,455)	102,904
	Interest & Dividend Affiliated	**59,001**	**2,552**	**(46,455)**	**102,904**
	Total Interest & Dividend Income	**168,251**	**51,042**	**10,345**	**106,865**
4210036	Carrying Charges	45,817	0	0	45,817
	Interest & Dividend Carrying Charge	**45,817**	-	-	**45,817**
	Memo: Total Interest & Dividend Income w/ Carrying	**214,068**	**51,042**	**10,345**	**152,682**
4191000	Allw Oth Fnds Usd Dring Cnstr	3,485,786	300,822	2,037,160	1,147,805
	AFUDC	**3,485,786**	**300,822**	**2,037,160**	**1,147,805**
	Gain on Disposition of Equity Investments	-	-	-	-
	Interest LTD FMB	-	-	-	-
4270002	Int on LTD - Install Pur Contr	10,507	10,507	0	0
	Interest LTD IPC	**10,507**	**10,507**	-	-
4300001	Interest Exp - Assoc Non-CBP	787,500	302,336	247,620	237,544
	Interest LTD Notes Payable - Affiliated	**787,500**	**302,336**	**247,620**	**237,544**
	Interest LTD Notes Payable - NonAffiliated	-	-	-	-
	Interest LTD Debentures	-	-	-	-
4270006	Int on LTD - Sen Unsec Notes	25,499,030	9,789,559	8,017,858	7,691,612
	Interest LTD Senior Unsecured	**25,499,030**	**9,789,559**	**8,017,858**	**7,691,612**
4270012	PCRB Interest Exp-Assoc	14,193	14,193	0	0
	Interest LTD Other - Affil	**14,193**	**14,193**	-	-
4270005	Int on LTD - Other LTD	2,176,806	2,183,403	(6,597)	0
	Interest LTD Other - NonAffil	**2,176,806**	**2,183,403**	**(6,597)**	-
	Interest on Long-Term Debt	**28,488,035**	**12,299,998**	**8,258,881**	**7,929,156**
4300003	Int to Assoc Co - CBP	28,078	5,257	171,182	(148,361)
	Interest STD - Affil	**28,078**	**5,257**	**171,182**	**(148,361)**
4310007	Lines Of Credit	644,066	233,072	355,380	55,614
	Interest STD - NonAffil	**644,066**	**233,072**	**355,380**	**55,614**
	Interest on Short Term Debt	**672,144**	**238,328**	**526,562**	**(92,747)**
4280002	Amrtz Debt Dscnt&Exp-Instl Pur	5,280	0	5,280	0
4280006	Amrtz Dscnt&Exp-Sn Unsec Note	356,202	136,744	111,996	107,463
	Amort of Debt Disc. Prem & Exp	**361,482**	**136,744**	**117,275**	**107,463**
4281004	Amrtz Loss Rcquired Debt-Dbnt	25,236	9,689	7,935	7,612
	Amort Loss on Reacquired Debt	**25,236**	**9,689**	**7,935**	**7,612**
	Amort Gain on Reacquired Debt	-	-	-	-
	Other Interest - Fuel Recovery	-	-	-	-
4310001	Other Interest Expense	70,905	20,594	41,552	8,760
4310002	Interest on Customer Deposits	21,783	21,783	0	0
4310023	Interest Expense - State Tax	(29,933)	(14,313)	(14,961)	(659)
	Other Interest - NonAffil	**62,755**	**28,064**	**26,591**	**8,101**

American Electric Power

GLS8016
YTD Sep 2014
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INCOME STATEMENT

Layout: GLS8016

09B V2014-09-30	Account: GL_ACCT_SEC Business Units: SEGMENT_CONS	Kentucky Power Int Consol GLS8016 Actual YTD Sep 2014	Kentucky Power Company - Distribution 110 Actual YTD Sep 2014	Kentucky Power Company - Generation 117 Actual YTD Sep 2014	Kentucky Power Company - Transmission 180 Actual YTD Sep 2014
	Other Interest Expense - Affil	-	-	-	-
	Interest Rate Hedge Unrealized (Gain)/Loss	-	-	-	-
4320000	Alw Brrwed Fnds Used Cnstr-Cr	(1,763,111)	(149,118)	(1,041,457)	(572,536)
	AFUDC-Borrowed Funds	**(1,763,111)**	**(149,118)**	**(1,041,457)**	**(572,536)**
	Total Interest Charges	**27,846,542**	**12,563,705**	**7,895,787**	**7,387,050**
	INCOME BEFORE INCOME TAXES and EQUITY EARNINGS	**93,997,075**	**4,375,260**	**41,030,137**	**48,591,677**
	INCOME TAXES and EQUITY EARNINGS				
4091001	Income Taxes, UOI - Federal	32,851,544	3,843,020	15,399,805	13,608,719
4092001	Inc Tax Oth Inc&Ded-Federal	(436,715)	(330,007)	(73,973)	(32,735)
	Federal Current Income Tax	**32,414,829**	**3,513,013**	**15,325,832**	**13,575,984**
4101001	Prov Def I/T Util Op Inc-Fed	32,062,655	3,362,559	25,893,288	2,806,808
4102001	Prov Def I/T Oth I&D - Federal	543,968	281,440	209,886	52,640
4111001	Prv Def I/T-Cr Util Op Inc-Fed	(35,680,591)	(5,545,038)	(29,040,486)	(1,095,065)
4112001	Prv Def I/T-Cr Oth I&D-Fed	(61,273)	0	(61,273)	0
	Federal Deferred Income Tax	**(3,135,244)**	**(1,901,039)**	**(2,998,587)**	**1,764,383**
4114001	ITC Adj, Utility Oper - Fed	(72,028)	(11,340)	(17,334)	(43,354)
	Federal Investment Tax Credits	**(72,028)**	**(11,340)**	**(17,334)**	**(43,354)**
	Federal Income Taxes	**29,207,558**	**1,600,634**	**12,309,911**	**15,297,013**
409100214	Income Taxes UOI - State	5,716,552	126,263	3,215,043	2,375,245
409200214	Inc Tax Oth Inc Ded - State	(75,800)	(57,279)	(12,839)	(5,682)
	State Current Income Tax	**5,640,751**	**68,984**	**3,202,204**	**2,369,563**
4111002	Prv Def I/T-Cr UtilOpInc-State	(458,640)	0	(458,640)	0
	State Deferred Income Tax	**(458,640)**	-	**(458,640)**	-
	State Investment Tax Credits	-	-	-	-
	State Income Taxes	**5,182,111**	**68,984**	**2,743,564**	**2,369,563**
	Local Current Income Tax	-	-	-	-
	Local Deferred Income Tax	-	-	-	-
	Local Investment Tax Credits	-	-	-	-
	Local Income Taxes	-	-	-	-
	Foreign Current Income Tax	-	-	-	-
	Foreign Deferred Income Tax	-	-	-	-
	Foreign Investment Tax Credits	-	-	-	-
	Foreign Income Taxes	-	-	-	-
	Total Income Taxes	**34,389,669**	**1,669,618**	**15,053,475**	**17,666,576**
	Equity Earnings of Subs	-	-	-	-
	INCOME AFTER INCOME TAXES and EQUITY EARNINGS	**59,607,406**	**2,705,642**	**25,976,662**	**30,925,101**
	Discontinued Operations (Net of Taxes)	-	-	-	-
	Cumulative Effect of Accounting Changes	-	-	-	-
	Extraordinary Income / (Expenses)	-	-	-	-
	NET INCOME	**59,607,406**	**2,705,642**	**25,976,662**	**30,925,101**
	Minority Interest	-	-	-	-
	Preferred Stock Dividend Subs	-	-	-	-
	Earnings to Common Shareholders	**59,607,406**	**2,705,642**	**25,976,662**	**30,925,101**
	NET INCOME (LOSS) NODE before PS	**59,607,406**	**2,705,642**	**25,976,662**	**30,925,101**
	Double Check on Net Income Node after PS	(0)	(0)	0	0

Reserved Section

AMERICAN ELECTRIC POWER COMPANY

BALANCE SHEET

GLS8216

YTD Sep 2014

10/08/2014 13:31

Layout : GLS8216

09B V2014-09- Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS

	Kentucky Power Int Consol GLS8216	Kentucky Power Company - 110	Kentucky Power Company - Generation 117	Kentucky Power Company - 180
	YTD Sep 2014	YTD Sep 2014	YTD Sep 2014	YTD Sep 2014
ASSETS				
Cash and Cash Equivalents	653,790	653,790	0	0
Other Cash Deposits	0	0	0	0
Customers	3,519,779	(1,174,914)	2,683,155	2,011,539
Accrued Unbilled Revenues	0	(391,067)	391,067	0
Miscellaneous Accounts Receivable	34,906,486	126,493,673	107,218,297	47,667,534
Allowances for Uncollectible Accounts	(23,817)	(16,914)	(6,903)	0
Accounts Receivable	38,402,449	124,910,779	110,285,615	49,679,073
Advances to Affiliates	9,577,118	(17,937,690)	(46,452,410)	73,967,218
Fuel, Materials and Supplies	71,679,801	2,157,892	68,631,636	890,273
Risk Management Contracts - Current	4,345,901	0	4,345,901	0
Margin Deposits	1,051,125	16,171	1,034,954	0
Unrecovered Fuel - Current	8,990,089	0	8,990,089	0
Other Current Regulatory Assets	0	0	0	0
Prepayments and Other Current Assets	2,764,063	2,007,587	607,877	148,599
TOTAL CURRENT ASSETS	137,464,336	111,808,530	147,443,661	124,685,163
Electric Production	1,148,472,729	763,811,201	1,612,419,787	518,482,388
Electric Transmission	521,653,925	0	0	0
Electric Distribution	717,881,758	0	0	0
General Property, Plant and Equipment	512,234,399	199,571	4,169,386	1,160,479
Construction Work-In-Progress	80,210,718	9,696,009	32,569,978	37,944,731
TOTAL PROPERTY, PLANT and EQUIPMENT	2,980,453,529	773,706,780	1,649,159,152	557,587,597
less: Accumulated Depreciation and Amortization	(1,003,004,139)	(246,597,678)	(584,207,412)	(172,199,049)
NET PROPERTY, PLANT and EQUIPMENT	1,977,449,391	527,109,102	1,064,951,740	385,388,548
Net Regulatory Assets	218,681,122	101,217,257	61,713,375	55,750,490
Securitized Transition Assets and Other	0	0	0	0
Spent Nuclear Fuel and Decommissioning Trusts	0	0	0	0
Investments in Power and Distribution Projects	0	0	0	0
Goodwill	0	0	0	0
Long-Term Risk Management Assets	1,336,252	0	1,336,252	0
Employee Benefits and Pension Assets	16,074,609	160,001	15,473,918	440,691
Other Non Current Assets	7,954,079	2,939,773	3,529,480	1,484,826
TOTAL OTHER NON-CURRENT ASSETS	244,046,062	104,317,031	82,053,025	57,676,007
TOTAL ASSETS	2,358,959,788	743,234,662	1,294,448,425	567,749,718
LIABILITIES				
Accounts Payable	91,366,477	131,073,972	200,684,538	6,080,985
Advances from Affiliates	0	0	0	0
Short-Term Debt	0	0	0	0
Other Current Regulatory Liabilities	0	0	0	0
Long-Term Debt Due Within One Year Non-Affiliated	65,000,000	0	65,000,000	0
Long-Term Debt Due Within One Year - Affiliated	20,000,000	7,614,600	6,233,800	6,151,600
Risk Management Liabilities	2,083,963	(6,770)	2,090,733	0
Accrued Taxes	39,297,357	9,371,577	15,222,222	14,703,557
Memo: Property Taxes	12,186,843	6,145,167	2,256,450	3,785,226
Accrued Interest	5,563,851	2,123,469	1,742,152	1,698,230
Risk Management Collateral	307,092	0	307,092	0
Utility Customer Deposits	25,260,450	25,260,450	0	0
Deposits - Customer and Collateral	25,567,542	25,260,450	307,092	0
Over-Recovered Fuel Costs - Current	0	0	0	0
Dividends Declared	0	0	0	0
Preferred Stock due W/IN 1 Yr	0	0	0	0
Obligations under Capital Leases - Current	1,135,747	483,159	509,013	143,574
Tax Collections Payable	2,296,476	2,200,692	88,505	7,279
Revenue Refunds - Accrued	1,149,493	0	29,897	1,119,596
Accrued Rents - Rockport	0	0	0	0
Accrued - Payroll	2,093,459	802,633	1,188,954	101,872
Accrued Rents	6,423	6,423	0	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Sep 2014
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Layout : GLS8216

09B V2014-09-	Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	Kentucky Power Int Consol GLS8216 YTD Sep 2014	Kentucky Power Company - 110 YTD Sep 2014	Kentucky Power Company - Generation 117 YTD Sep 2014	Kentucky Power Company - 180 YTD Sep 2014
	Accrued ICP	5,449,971	2,185,992	3,063,036	200,943
	Accrued Vacations	4,998,899	2,018,737	2,717,608	262,554
	Misc Employee Benefits	1,501,871	544,607	924,007	33,257
	Payroll Deductions	174,164	75,671	88,959	9,534
	Severance / SEI	0	0	0	0
	Accrued Workers Compensation	711,604	297,137	386,268	28,199
2530022	Customer Advance Receipts	1,505,492	1,505,492	0	0
	Customer Advance	1,505,492	1,505,492	0	0
2420511	Control Cash Disburse Account	1,053,290	1,053,290	0	0
	Control Cash Disbursement Account	1,053,290	1,053,290	0	0
	JMG Liability	0	0	0	0
2420088	Econ Development Fund Curr	174,750	0	174,750	0
2420506	Est Financing Cost - Bonds	(133,127)	0	(133,127)	0
2420512	Unclaimed Funds	62,948	62,948	0	0
2420542	Acc Cash Franchise Req	70,093	70,093	0	0
242059214	Sales Use Tax - Lease Equip	291	0	218	73
2420643	Accrued Audit Fees	118,004	30,788	67,896	19,320
2420656	Federal Mitigation Accru (NSR)	554,326	0	554,326	0
2420664	ST State Mitigation Def (NSR)	173,104	0	173,104	0
2530050	Deferred Rev -Pole Attachments	247,227	247,227	0	0
2530112	Other Deferred Credits-Curr	230,828	9,212	221,616	0
2530124	Contr In Aid of Constr Advance	38,321	38,321	0	0
2530177	Deferred Rev-Bonus Lease Curr	431,564	0	431,564	0
	Misc Current and Accrued Liabilities	1,968,328	458,588	1,490,346	19,394
	Current Other and Accrued Liabilities	22,909,470	11,149,263	9,977,580	1,782,627
	Other Current Liabilities	24,045,217	11,632,422	10,486,593	1,926,202
	TOTAL CURRENT LIABILITIES	272,924,406	187,069,719	301,767,130	30,560,574
	Long-Term Debt - Affiliated	**0**	**0**	**0**	**0**
	Long-Term Debt - Non Affiliated	**730,000,000**	**247,474,500**	**282,598,500**	**199,927,000**
	Long-Term Debt - Premiums and Discounts Unamort	(486,281)	(185,142)	(151,569)	(149,570)
	Memo - LTD NonAffiliated and Premiums	*729,513,719*	*247,289,358*	*282,446,931*	*199,777,430*
	Long-Term Risk Management Liabilities - Hedge	0	0	0	0
2440002	LT Unreal Losses - Non Affil	627,940	7,967	619,973	0
2440022	L/T Liability MTM Collateral	(12,514)	(9,217)	(3,297)	0
	Long-Term Risk Management Liabilities - MTM	615,426	(1,250)	616,676	0
	Long-Term Risk Management Liabilities	**615,426**	(1,250)	**616,676**	**0**
	Deferred Income Taxes	**552,969,299**	**168,393,166**	**264,627,777**	**119,948,356**
	Deferred Investment Tax Credits	**53,719**	**12,825**	**20,494**	**20,401**
	Regulatory Liabilities and Deferred Credits	**22,542,184**	(33,105,523)	**62,102,424**	(6,454,717)
	Memo - Reg Liab and Def ITC	*22,595,903*	*(33,092,698)*	*62,122,918*	*(6,434,317)*
	Asset Retirement Obligation	**64,112,917**	**63,623**	**64,049,294**	**0**
	Nuclear Decommissioning	**0**	**0**	**0**	**0**
	Employee Benefits and Pension Obligations	**7,863,534**	**2,956,237**	**4,806,418**	**100,880**
	Trust Preferred Securities	**0**	**0**	**0**	**0**
	Cumulative Preferred Stocks of Subs - Mandatory Rede	**0**	**0**	**0**	**0**
	Obligations Under Capital Leases	3,370,535	1,298,283	1,635,240	437,013
	Def Credits - Income Tax	84,201	43,549	12,298	28,354
2530114	Federl Mitigation Deferal(NSR)	1,110,644	0	1,110,644	0
	Def Credits - NSR	1,110,644	0	1,110,644	0
	Customer Advances for Construction	117,511	117,511	0	0
	Def Gain on Sale/Leaseback	0	0	0	0
	Deferred Gain on Sale and Leaseback - Rockport	0	0	0	0
	Def Gain on Disp of Utility Plant	0	0	0	0
2530000	Other Deferred Credits	3,738	0	3,738	0
2530067	IPP - System Upgrade Credits	275,431	0	0	275,431
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	152,086	152,086	0	0
2530101	MACSS Unidentified EDI Cash	0	0	0	0
2530137	Fbr Opt Lns-Sold-Defd Rev	93,007	0	0	93,007
2530178	Deferred Rev-Bonus Lease NC	1,546,438	0	1,546,438	0
	Def Credits - Other	2,070,700	152,086	1,550,176	368,437
	Total Other Deferred Credits	2,188,211	269,597	1,550,176	368,437
	Accumulated Provisions - Rate Refund	0	0	0	0

AMERICAN ELECTRIC POWER COMPANY
BALANCE SHEET
GLS8216
YTD Sep 2014
10/08/2014 13:31

Layout : GLS8216

09B V2014-09- Account: GL_ACCT_SEC Business Unit: SEGMENT_CONS	Kentucky Power Int Consol GLS8216 YTD Sep 2014	Kentucky Power Company - 110 YTD Sep 2014	Kentucky Power Company - Generation 117 YTD Sep 2014	Kentucky Power Company - 180 YTD Sep 2014
Accumulated Provisions - Misc	757,250	0	757,250	0
Other Non-Current Liabilities	7,510,840	1,611,429	5,065,607	833,804
TOTAL NON-CURRENT LIABILITIES	1,385,181,638	387,219,865	683,735,620	314,226,153
TOTAL LIABILITIES	1,658,106,044	574,289,584	985,502,750	344,786,727
Cumulative Pref Stocks of Subs - Not subject Mand Redem	0	0	0	0
Minority Interest - Deferred Credits	0	0	0	0
COMMON SHAREHOLDERS' EQUITY				
Common Stock	50,450,000	22,404,049	10,287,603	17,758,348
Paid In Capital	517,459,453	106,025,371	327,394,246	84,039,836
Premium on Capital Stock	0	0	0	0
Retained Earnings	139,298,330	40,582,754	(22,503,436)	121,219,012
Accumulated Other Comprehensive Income (Loss)	(6,354,038)	(67,096)	(6,232,738)	(54,205)
TOTAL SHAREHOLDERS' EQUITY	700,853,745	168,945,079	308,945,675	222,962,991
Memo: Total Equity	700,853,745	168,945,079	308,945,675	222,962,991
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	2,358,959,788	743,234,662	1,294,448,425	567,749,718
out-of-balance	(0)	0	0	(0)

Reserved Section

Kentucky Power Corp Consol
Comparative Balance Sheet
September 30, 2013

Run Date: 10/09/2013 14:39

X_OPR_COS Rpt ID: GLR2200V Layout: GLR2200V
KYP_CORP_CI V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS

	Month End Balances 2013	December Balances Last Year	Variance $
ASSETS			
PRODUCTION	560,511,005.62	558,934,668.00	1,576,337.62
TRANSMISSION	491,308,853.23	490,152,082.00	1,156,771.23
DISTRIBUTION	678,308,268.07	652,615,328.83	25,692,939.24
GENERAL	61,527,321.61	57,451,300.18	4,076,021.43
CONSTRUCTION WORK IN PROGRESS	57,588,482.21	44,281,291.91	13,307,190.30
ELECTRIC UTILITY PLANT	**1,849,243,930.74**	**1,803,434,670.92**	**45,809,259.82**
less Accum Provision - Depre, Depl, Amort.	(653,330,462.34)	(624,238,902.51)	(29,091,559.83)
NET ELECTRIC UTILITY PLANT	**1,195,913,468.40**	**1,179,195,768.41**	**16,717,699.99**
Net NonUtility Property	2,685,724.31	5,498,717.60	(2,812,993.29)
Investment in Subsidiary & Associated	0.00	0.00	0.00
Other Investments	256,467.67	260,727.67	(4,260.00)
Other Special Funds	0.00	0.00	0.00
Allowance - NonCurrent	2,361,233.00	2,361,232.37	0.63
Long Term Energy Trading Contracts	4,293,823.73	6,881,654.77	(2,587,831.04)
OTHER PROPERTY AND INVESTMENTS	**9,597,248.71**	**15,002,332.41**	**(5,405,083.70)**
Cash and Cash Equivalents	1,239,844.35	1,925,747.09	(685,902.74)
Advances to Affiliates	6,300,209.02	0.00	6,300,209.02
Acct Rec - Customers	5,292,987.24	12,676,052.64	(7,383,065.40)
Acct Rec - Miscellaneous	2,132,776.72	3,141,697.43	(1,008,920.71)
Acct Rec - AP for Uncollectible Accounts	(68,626.62)	(141,538.08)	72,911.46
Acct Rec - Associated Companies	9,290,122.35	9,241,088.58	49,033.77
Fuel Stock	54,323,865.24	69,147,176.47	(14,823,311.23)
Materials and Supplies	20,259,349.70	25,061,279.42	(4,801,929.72)
Accrued Utility Revenues	48,846.07	816,939.53	(768,093.46)
Energy Trading	5,041,531.97	6,174,819.72	(1,133,287.75)
Prepayments	2,006,581.35	1,569,794.80	436,786.55
Other Current Assets	1,102,209.48	1,660,942.94	(558,733.46)
CURRENT ASSETS	**106,969,696.86**	**131,274,000.53**	**(24,304,303.67)**
REGULATORY ASSETS	**204,164,561.05**	**214,900,829.18**	**(10,736,268.13)**
TOTAL DEFERRED CHARGES	**44,101,374.30**	**78,498,798.33**	**(34,397,424.03)**
TOTAL ASSETS	**1,560,746,349.32**	**1,618,871,728.86**	**(58,125,379.54)**
CAPITALIZATION and LIABILITIES			
COMMON STOCK			
Authorized: 2,000,000 Shares			
Outstanding: 1,009,000 Shares			
Common Stock	50,450,000.00	50,450,000.00	0.00
Premium on Capital Stock	0.00	0.00	0.00
Paid-In-Capital	238,506,174.80	238,341,119.49	165,055.31
Retained Earnings	179,460,940.04	190,818,915.56	(11,357,975.53)
COMMON SHAREHOLDERS' EQUITY	**468,417,114.84**	**479,610,035.05**	**(11,192,920.22)**
PS Subject To Mandatory Redemption	0.00	0.00	0.00
PS Not Subject Mandatory Redemption	0.00	0.00	0.00

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Kentucky Power Corp Consol
Comparative Balance Sheet
September 30, 2013

Run Date: 10/09/2013 14:39

X_OPR_COS / KYP_CORP_C(	Rpt ID: GLR2200V Layout: GLR2200V / V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
	CUMULATIVE PREFERRED STOCK	0.00	0.00	0.00
	TRUST PREFERRED SECURITIES	0.00	0.00	0.00
	Long-Term Debt Less Amt Due 1 Yr	549,346,993.75	549,221,950.00	125,043.75
	CAPITALIZATION	1,017,764,108.59	1,028,831,985.05	(11,067,876.47)
	Obligations Under Capital Lease-NonCurrent	1,872,461.75	1,674,300.89	198,160.86
	Accumulated Provision Rate Relief	0.00	1,635,430.00	(1,635,430.00)
	Accumlated Provision - Miscellanous	33,529,323.17	34,033,794.12	(504,470.95)
	Other NonCurrent Liabilities	35,401,784.92	37,343,525.01	(1,941,740.09)
	Preferred Stock Due Within 1 Year	0.00	0.00	0.00
	Long-Term Debt Due Within 1 Year	0.00	0.00	0.00
	Accumulated Provision Due Within 1 Year	0.00	0.00	0.00
	Short-Term Debt	0.00	0.00	0.00
	Advances from Affiliates	0.00	13,358,855.63	(13,358,855.63)
	A/P General	18,892,719.15	30,336,776.64	(11,444,057.49)
	A/P Associated Companies	29,915,408.66	41,052,680.18	(11,137,271.52)
	Customer Deposits	24,769,417.37	23,484,964.81	1,284,452.56
	Taxes Accrued	5,475,503.58	6,548,714.64	(1,073,211.06)
	Interest Accrued	5,104,735.71	7,166,695.02	(2,061,959.31)
	Dividends Accrued	0.00	0.00	0.00
	Obligation Under Capital Leases	1,167,112.52	1,403,875.95	(236,763.43)
	Energy Contracts Current	2,382,683.51	3,320,068.02	(937,384.51)
	Other Current and Accrued Liabilities	14,934,867.47	17,797,808.10	(2,862,940.63)
	Current Liabilities	102,642,447.97	144,470,438.99	(41,827,991.02)
	Deferred Income Taxes	388,432,046.15	385,153,166.17	3,278,879.98
	Deferred Investment Tax Credits	183,252.04	355,758.82	(172,506.78)
	Regulatory Liabilities	10,183,753.39	13,831,965.72	(3,648,212.33)
2440002	LT Unreal Losses - Non Affil	2,702,317.30	4,200,196.07	(1,497,878.77)
2440022	L/T Liability MTM Collateral	(216,446.00)	(582,545.00)	366,099.00
2450011	L/T Liability-Commodity Hedges	3,392.00	82,731.00	(79,339.00)
	Long-Term Energy Trading Contracts	2,489,263.30	3,700,382.07	(1,211,118.77)
2520000	Customer Adv for Construction	101,947.71	63,177.74	38,769.97
	Customer Advances for Construction	101,947.71	63,177.74	38,769.97
	Deferred Gains on Sale/Leaseback	0.00	0.00	0.00
	Deferred Gains on Dispostion of Utility Plant	0.00	0.00	0.00
2530000	Other Deferred Credits	0.00	0.00	0.00
2530022	Customer Advance Receipts	1,774,062.09	2,634,497.53	(860,435.44)
2530050	Deferred Rev -Pole Attachments	245,283.25	78,940.35	166,342.90
2530067	IPP - System Upgrade Credits	266,658.07	260,279.72	6,378.35
2530092	Fbr Opt Lns-In Kind Sv-Dfd Gns	158,354.00	162,614.00	(4,260.00)
2530101	MACSS Unidentified EDI Cash	83.81	0.00	83.81
2530112	Other Deferred Credits-Curr	241,799.92	1,113,326.72	(871,526.80)

Kentucky Power Corp Consol
Comparative Balance Sheet
September 30, 2013

Run Date: 10/09/2013 14:39

X_OPR_COS / KYP_CORP_C(	Rpt ID: GLR2200V Layout: GLR2200V / V2099-01-01 Acct: PRPT_ACCOUNT BU: GL_PRPT_CONS	Month End Balances 2013	December Balances Last Year	Variance $
2530114	Federl Mitigation Deferal(NSR)	754,941.55	754,941.55	0.00
2530137	Fbr Opt Lns-Sold-Defd Rev	106,562.57	116,729.42	(10,166.85)
	Other Deferred Credits	3,547,745.26	5,121,329.29	(1,573,584.03)
	Deferred Credits	**6,138,956.27**	**8,884,889.10**	(2,745,932.83)
	DEFERRED CREDITS & REGULATED LIABILITIES	**404,938,007.85**	**408,225,779.81**	(3,287,771.96)
	CAPITAL & LIABILITIES	**1,560,746,349.33**	**1,618,871,728.87**	(58,125,379.54)

Statement of Retained Earnings

	BALANCE AT BEGINNING OF YEAR	**190,818,915.56**	**171,840,462.36**	18,978,453.21
	Net Income (Loss)	7,392,024.47	50,978,453.21	(43,586,428.73)
	Deductions:			
	Dividend Declared On Common Stock	(18,750,000.00)	-32,000,000	13,250,000.00
	Dividend Declared On Preferred Stock	0.00	0	0.00
	Adjustment in Retained Earnings	0.00	0.00	(0.00)
	Total Deductions	(18,750,000.00)	(32,000,000.00)	13,250,000.00
	BALANCE AT END OF PERIOD (A)	**179,460,940.04**	**190,818,915.56**	(11,357,975.53)

(A) Represents The Following Balances At End Of Period

215.0	Appropriated Retained Earnings	0.00	0.00	0.00
215.1	Appr Retnd Erngs - Amrt Rsv, Fed	0.00	0.00	0.00
	Total Appropriated Retained Earnings	0.00	0.00	0.00
2160000-1	Unapprp Retained Earnings Unrestr	190,818,915.56	171,840,462.36	18,978,453.21
2160002+	Unapprp Retained Earnings Restr	0.00	0.00	0.00
210.0	Gain on Reacquired Pref Stock	0.00	0.00	0.00
	Net Income Transferred	(11,357,975.53)	18,978,453.21	(30,336,428.73)
	Total Unappropriated Retained Earnings	179,460,940.04	190,818,915.56	(11,357,975.53)
216.1	Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
418.1	Equity Earnings of Subsidiary Co	0.00	0.00	0.00
	Total Unapprop Undistributed Sub Earnings	0.00	0.00	0.00
	Total Other Retained Earnings Accounts	(0.00)	0.00	(0.00)
	TOTAL RETAINED EARNINGS	**179,460,940.04**	**190,818,915.56**	(11,357,975.53)

Final 10/08/2014

KENTUCKY POWER COMPANY
DETAIL OF ELECTRIC UTILITY PROPERTY
YEAR TO DATE - September, 2014

GLR7210V　　10/08/14 13:33

		BEGINNING BALANCE	ADDITIONS	ORIGINAL COST RETIREMENTS	ADJUSTMENTS	TRANSFERS	ENDING BALANCE
UTILITY PLANT							
101/106	GENERATION	1,478,684,251.88	126,806,316.39	(3,008,973.51)	(9.12)	0.00	1,602,481,585.64
	TOTAL PRODUCTION	**1,478,684,251.88**	**126,806,316.39**	**(3,008,973.51)**	**(9.12)**	**0.00**	**1,602,481,585.64**
101/106	TRANSMISSION	503,165,571.80	14,965,750.90	(461,802.95)	0.00	0.00	517,669,519.75
101/106	DISTRIBUTION	733,776,590.81	32,428,069.87	(5,700,111.07)	0.00	0.00	760,504,549.61
	TOTAL (ACCOUNTS 101 & 106)	**2,715,626,414.49**	**174,200,137.16**	**(9,170,887.63)**	**(9.12)**	**0.00**	**2,880,655,655.00**
1011001/12	CAPITAL LEASES	6,279,149.17	0.00	0.00	372,612.76	0.00	6,651,761.93
102	ELECTRIC PLT PURCHASED OR SOLD	0.00	0.00	0.00	0.00	0.00	0.00
1140001	ELECTRIC PLANT ACQUISITION	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ELECTRIC PLANT IN SERVICE	**2,721,905,563.66**	**174,200,137.16**	**(9,170,887.63)**	**372,603.64**	**0.00**	**2,887,307,416.93**
1050001	PLANT HELD FOR FUTURE USE	7,405,958.73	0.00	0.00	0.00	0.00	7,405,958.73
107000X	**CONSTRUCTION WORK IN PROGRESS:**						
107000X	BEG. BAL.	128,599,148.19					
107000X	ADDITIONS		83,233,894.26				
107000X	TRANSFERS		(131,622,324.53)				
107000X	END. BAL.		(48,388,430.27)				80,210,717.92
	TOTAL ELECTRIC UTILITY PLANT	**2,857,910,670.58**	**125,811,706.89**	**(9,170,887.63)**	**372,603.64**	**0.00**	**2,974,924,093.58**
NONUTILITY PLANT							
1210001	NONUTILITY PROPERTY-OWNED	995,120.00	0.00	0.00	0.00	0.00	995,120.00
1210002	NONUTILITY PROPERTY-LEASED	0.00	0.00	0.00	0.00	0.00	0.00
1240025-29	OTHER INVESTMENTS	4,534,315.74	0.00	0.00	(0.03)	0.00	4,534,315.71
	TOTAL NONUTILITY PLANT	**5,529,435.74**	**0.00**	**0.00**	**(0.03)**	**0.00**	**5,529,435.71**

Prepared by: PSnVision Report GLR7210V
Reviewer: Cindy Buckbee – Prop Acctg Canton
Sources of Info: Powerplant Reports and PS GL

Acct 107 Transfers	**(131,622,324.53)**
Acct 101/6 Additions	**174,200,137.16**
	42,577,812.63
ARO - ASH#1 Big Sandy Ash Pond 06/2014	**42,577,812.63**

KENTUCKY POWER COMPANY
ACCUMULATED PROVISION FOR DEPRECIATION, AMORTIZATION, & DEPLETION
YEAR TO DATE - September, 2014

		BEGINNING BALANCE	PROVISION TO DATE	ORIGINAL COST	NET REM/ SALV COST	TRANSFER/ ADJUSTMENTS	ENDING BALANCE
UTILITY PLANT							
	NUCLEAR						
1080001/11	OTHER					0.00	
1080009/10	DECOMMISSIONING COSTS					0.00	
	TOTAL NUCLEAR					0.00	
1080001/11	PRODUCTION	599,504,126.89	43,017,367.88	(3,008,973.51)	(1,784,047.24)	0.00	637,728,474.02
1080001/11	TRANSMISSION	161,537,795.16	6,512,502.21	(461,802.95)	(292,621.65)	0.00	167,295,872.77
1080001/11	DISTRIBUTION	192,744,660.64	19,126,430.02	(5,700,111.07)	(1,599,234.48)	0.00	204,571,745.11
1080013	PRODUCTION	(3,620,015.26)	0.00	0.00	0.00	(392,722.17)	(4,012,737.43)
1080013	TRANSMISSION	0.00	0.00	0.00	0.00	0.00	0.00
1080013	DISTRIBUTION	(26,698.85)	0.00	0.00	0.00	(6,903.37)	(33,602.22)
	RETIREMENT WORK IN PROGRESS	(8,320,252.52)	0.00	0.00	(4,490,952.86)	3,675,903.37	(9,135,302.01)
	TOTAL (108X accounts)	**941,819,616.07**	**68,656,300.11**	**(9,170,887.53)**	**(8,166,856.23)**	**3,276,277.83**	**996,414,450.25**
	NUCLEAR					0.00	
1110001	PRODUCTION	10,429,350.87	1,036,456.26	0.00	0.00	84,795.27	11,550,602.40
1110001	TRANSMISSION	1,607,792.68	449,758.61	0.00	0.00	0.00	2,057,551.29
1110001	DISTRIBUTION	7,182,584.75	1,160,416.09	0.00	0.00	0.00	8,343,000.84
	TOTAL (111X accounts)	**19,219,728.30**	**2,646,630.96**	**0.00**	**0.00**	**84,795.27**	**21,951,154.53**
1011006	CAPITAL LEASES	1,869,467.09	0.00	0.00	0.00	276,012.97	2,145,480.06
1150001	ACQUISITION ADJUSTMENT AMORT	0.00	0.00	0.00	0.00	0.00	0.00
	TOTAL ACCUM DEPR & AMORT.	**962,908,811.46**	**71,302,931.07**	**(9,170,887.53)**	**(8,166,856.23)**	**3,637,086.07**	**1,020,511,084.84**
NONUTILITY PLANT							
1220001	Depr&Amrt of Nonuti Prop-Ownd	214,955.75	5,002.29	0.00	0.00	0.00	219,958.04
1240027	Other Property - RWIP	(3,400.00)	0.00	0.00	0.00	(395.00)	(3,795.00)
	TOTAL NONUTILITY PLANT	**211,555.75**	**5,002.29**	**0.00**	**0.00**	**(395.00)**	**216,163.04**

Prepared By: PSnVision Report GLR7410V
Reviewer: Cindy Buckbee -- Prop Acctg. Canton
Sources of Info: PowerPlant Reports and PS GL

Filing Requirement
807 KAR 5:001 Section 16 (4)(s)

Filing Requirement:

A copy of the utility's annual report on Form 10-K as filed with the Securities and Exchange Commission for the most recent two (2) years, any Form 8-K issued during the past two (2) years, and any Form 10-Q issued during the past six (6) quarters updated as current information becomes available;

Response:

Kentucky Power Company is no longer a registrant with the Securities and Exchange Commission and has not filed Forms 10-K, 10-Q, or 8-K since 2007.

The following Company reports to the Board of Directors and Shareholders are attached:

Kentucky Power Company 2013 Q1 Quarterly
Kentucky Power Company 2013 Q2 Quarterly
Kentucky Power Company 2013 Q3 Quarterly
Kentucky Power Company 2014 Q1 Quarterly
Kentucky Power Company 2014 Q2 Quarterly
Kentucky Power Company 2014 Q3 Quarterly

Please see 807 KAR 5:001 Section 16 (4)(q) for Kentucky Power's annual reports.

Kentucky Power Company

2013 First Quarter Report

Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., a utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
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.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2013	2012
REVENUES		
Electric Generation, Transmission and Distribution	$ 166,418	$ 158,803
Sales to AEP Affiliates	14,554	5,025
Other Revenues	132	202
TOTAL REVENUES	181,104	164,030
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	43,721	29,985
Purchased Electricity for Resale	3,370	3,994
Purchased Electricity from AEP Affiliates	57,664	56,028
Other Operation	13,267	14,343
Maintenance	11,696	18,794
Depreciation and Amortization	14,666	13,541
Taxes Other Than Income Taxes	3,135	3,193
TOTAL EXPENSES	147,519	139,878
OPERATING INCOME	33,585	24,152
Other Income (Expense):		
Interest Income	27	122
Allowance for Equity Funds Used During Construction	261	699
Interest Expense	(8,885)	(8,765)
INCOME BEFORE INCOME TAX EXPENSE	24,988	16,208
Income Tax Expense	8,226	5,190
NET INCOME	$ 16,762	$ 11,018

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2013	2012
Net Income	$ 16,762	$ 11,018
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES		
Cash Flow Hedges, Net of Tax of $118 and $65 in 2013 and 2012, Respectively	218	(121)
TOTAL COMPREHENSIVE INCOME	$ 16,980	$ 10,897

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 50,450	$ 238,750	$ 171,841	$ (625)	$ 460,416
Common Stock Dividends			(8,000)		(8,000)
Net Income			11,018		11,018
Other Comprehensive Loss				(121)	(121)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2012	$ 50,450	$ 238,750	$ 174,859	$ (746)	$ 463,313
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 50,450	$ 238,750	$ 190,819	$ (409)	$ 479,610
Common Stock Dividends			(6,250)		(6,250)
Net Income			16,762		16,762
Other Comprehensive Income				218	218
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	$ 50,450	$ 238,750	$ 201,331	$ (191)	$ 490,340

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2013 and December 31, 2012
(in thousands)
(Unaudited)

	March 31, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 862	$ 1,482
Accounts Receivable:		
Customers	18,630	15,666
Affiliated Companies	5,319	10,152
Accrued Unbilled Revenues	1,794	817
Miscellaneous	84	151
Allowance for Uncollectible Accounts	(9)	(142)
Total Accounts Receivable	25,818	26,644
Fuel	47,169	69,147
Materials and Supplies	22,425	25,061
Risk Management Assets	4,622	6,175
Accrued Tax Benefits	3,679	5,186
Prepayments and Other Current Assets	5,551	6,626
TOTAL CURRENT ASSETS	110,126	140,321
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	560,292	558,935
Transmission	490,860	490,152
Distribution	663,710	652,615
Other Property, Plant and Equipment	64,383	63,151
Construction Work in Progress	43,808	44,281
Total Property, Plant and Equipment	1,823,053	1,809,134
Accumulated Depreciation and Amortization	613,219	603,373
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,209,834	1,205,761
OTHER NONCURRENT ASSETS		
Regulatory Assets	214,240	213,734
Long-term Risk Management Assets	4,949	6,882
Deferred Charges and Other Noncurrent Assets	45,537	48,880
TOTAL OTHER NONCURRENT ASSETS	264,726	269,496
TOTAL ASSETS	$ 1,584,686	$ 1,615,578

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2013 and December 31, 2012
(Unaudited)

	March 31, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 11,039	$ 13,359
Accounts Payable:		
General	21,553	30,337
Affiliated Companies	18,422	40,965
Risk Management Liabilities	2,380	3,320
Customer Deposits	23,958	23,485
Accrued Taxes	11,688	11,818
Accrued Interest	5,575	7,210
Regulatory Liability for Over-Recovered Fuel Costs	-	7,928
Other Current Liabilities	23,321	25,685
TOTAL CURRENT LIABILITIES	117,936	164,107
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	529,264	529,222
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,630	3,700
Deferred Income Taxes	358,249	353,578
Regulatory Liabilities and Deferred Investment Tax Credits	25,557	26,159
Employee Benefits and Pension Obligations	32,124	30,981
Deferred Credits and Other Noncurrent Liabilities	8,586	8,221
TOTAL NONCURRENT LIABILITIES	976,410	971,861
TOTAL LIABILITIES	1,094,346	1,135,968
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	238,750
Retained Earnings	201,331	190,819
Accumulated Other Comprehensive Income (Loss)	(191)	(409)
TOTAL COMMON SHAREHOLDER'S EQUITY	490,340	479,610
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 1,584,686	$ 1,615,578

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2013	2012
OPERATING ACTIVITIES		
Net Income	$ 16,762	$ 11,018
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	14,666	13,541
Deferred Income Taxes	6,096	(1,191)
Allowance for Equity Funds Used During Construction	(261)	(699)
Mark-to-Market of Risk Management Contracts	1,798	(22)
Fuel Over/Under-Recovery, Net	(7,945)	5,784
Change in Other Noncurrent Assets	3,278	(1,052)
Change in Other Noncurrent Liabilities	75	(135)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	826	11,412
Fuel, Materials and Supplies	24,614	(5,081)
Accounts Payable	(27,906)	(13,128)
Customer Deposits	473	315
Accrued Taxes, Net	1,377	4,881
Other Current Assets	912	603
Other Current Liabilities	(6,661)	(6,990)
Net Cash Flows from Operating Activities	28,104	19,256
INVESTING ACTIVITIES		
Construction Expenditures	(20,558)	(23,660)
Change in Advances to Affiliates, Net	-	12,454
Other Investing Activities	452	83
Net Cash Flows Used for Investing Activities	(20,106)	(11,123)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(2,320)	-
Principal Payments for Capital Lease Obligations	(245)	(304)
Dividends Paid on Common Stock	(6,250)	(8,000)
Other Financing Activities	197	6
Net Cash Flows Used for Financing Activities	(8,618)	(8,298)
Net Decrease in Cash and Cash Equivalents	(620)	(165)
Cash and Cash Equivalents at Beginning of Period	1,482	778
Cash and Cash Equivalents at End of Period	$ 862	$ 613
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 10,315	$ 10,459
Net Cash Paid for Income Taxes	111	186
Noncash Acquisitions Under Capital Leases	590	152
Construction Expenditures Included in Current Liabilities as of March 31,	6,115	7,819

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

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2013 is not necessarily indicative of results that may be expected for the year ending December 31, 2013. The condensed financial statements are unaudited and should be read in conjunction with the audited 2012 financial statements and notes thereto, which are included in KPCo's 2012 Annual Report.

Management reviewed subsequent events through April 26, 2013, the date that the first quarter 2013 report was issued.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following table provides the components of changes in AOCI for the three months ended March 31, 2013. All amounts in the following table are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (409)
Change in Fair Value Recognized in AOCI	161	-	161
Amounts Reclassified from AOCI	42	15	57
Net Current Period Other Comprehensive Income	203	15	218
Balance in AOCI as of March 31, 2013	$ 76	$ (267)	$ (191)

Reclassifications Out of Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the three months ended March 31, 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2013

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Commodity:	
Electric Generation, Transmission and Distribution Revenues	$ 19
Purchased Electricity for Resale	54
Other Operation Expense	(3)
Maintenance Expense	(2)
Property, Plant and Equipment	(4)
Subtotal - Commodity	64
Interest Rate and Foreign Currency:	
Interest Expense	23
Subtotal - Interest Rate and Foreign Currency	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	87
Income Tax (Expense) Credit	30
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 57

The following table provides details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2012. All amounts in the following table are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended March 31, 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	(350)	-	(350)
Amount of (Gain) or Loss Reclassified from AOCI to Statement of Income/within Balance Sheet:			
Purchased Electricity for Resale	216	-	216
Maintenance Expense	(1)	-	(1)
Interest Expense	-	15	15
Property, Plant and Equipment	(1)	-	(1)
Balance in AOCI as of March 31, 2012	$ (419)	$ (327)	$ (746)

3. RATE MATTERS

As discussed in KPCo's 2012 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2012 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2013 and updates KPCo's 2012 Annual Report.

Regulatory Assets Not Yet Being Recovered

Noncurrent Regulatory Assets	March 31, 2013	December 31, 2012
	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 12,146	$ 12,146
Medicare Part D	2,599	-
Mountaineer Carbon Capture and Storage Commercial Scale Facility	873	873
Total Regulatory Assets Not Yet Being Recovered	$ 15,618	$ 13,019

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

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 March 2013, KPCo issued a Request for Proposal to purchase up to 250 MW of long-term capacity and energy. KPCo also requested costs related to the Big Sandy Plant Unit 2 FGD project be established as a regulatory asset and be recovered in KPCo's next base rate case. As of March 31, 2013, KPCo has incurred $28 million related to the FGD project, which is recorded in Deferred Charges and Other Noncurrent Assets on the balance sheet.

In April 2013, the Kentucky Industrial Utility Customers, Inc. (KIUC) filed testimony that recommended (a) the one-half transfer interest of the Mitchell Plant be limited to a 20% interest contingent on a determination that the net book value is less than market value, (b) the transfer should occur on June 1, 2015 and (c) that the request to defer the FGD project costs be denied. If the Mitchell Plant transfer is approved, the KIUC requested that the shareholder's portion of off-system sales decrease from 40% to zero. A hearing at the KPSC is scheduled for May 2013. If KPCo is not ultimately permitted to recover its incurred costs, it could reduce future net income and cash flows and impact financial condition.

FERC Rate Matters

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). This transfer is proposed to be effective no later than December 31, 2013. Additionally, the AEP East Companies asked the FERC, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a new Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, KPCo would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision from the FERC is expected in the second quarter of 2013. Similar filings have been made at the KPSC. See the "Plant Transfer" section of Rate Matters.

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.

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. The Commitments, Guarantees and Contingencies note within KPCo's 2012 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2013, 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 conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2013, 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.

CONTINGENCIES

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 filed seeking 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.

5. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans for the three months ended March 31, 2013 and 2012:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	$ 257	$ 353	$ 111	$ 252
Interest Cost	1,235	1,366	458	709
Expected Return on Plan Assets	(1,605)	(1,848)	(737)	(728)
Amortization of Prior Service Cost (Credit)	10	21	(505)	(126)
Amortization of Net Actuarial Loss	1,118	919	421	392
Net Periodic Benefit Cost (Credit)	$ 1,015	$ 811	$ (252)	$ 499

6. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated 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 the KPCo's outstanding derivative contracts as of March 31, 2013 and December 31, 2012:

Notional Volume of Derivative Instruments

	Volume		
	March 31, 2013	**December 31, 2012**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	12,915	18,838	MWhs
Coal	43	247	Tons
Natural Gas	1,692	2,018	MMBtus
Heating Oil and Gasoline	288	269	Gallons
Interest Rate	$ 4,555	$ 4,836	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 condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2013 and December 31, 2012 condensed balance sheets, KPCo netted $379 thousand and $253 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $1.0 million and $2.2 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 KPCo's derivative activity on the condensed balance sheets as of March 31, 2013 and December 31, 2012:

Fair Value of Derivative Instruments
March 31, 2013

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 17,216	$ 248	$ -	$ 17,464	$ (12,842)	$ 4,622
Long-term Risk Management Assets	8,187	27	-	8,214	(3,265)	4,949
Total Assets	25,403	275	-	25,678	(16,107)	9,571
Current Risk Management Liabilities	15,562	134	-	15,696	(13,316)	2,380
Long-term Risk Management Liabilities	6,023	27	-	6,050	(3,420)	2,630
Total Liabilities	21,585	161	-	21,746	(16,736)	5,010
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,818	$ 114	$ -	$ 3,932	$ 629	$ 4,561

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 25,448	$ 72	$ -	$ 25,520	$ (19,345)	$ 6,175
Long-term Risk Management Assets	12,117	43	-	12,160	(5,278)	6,882
Total Assets	37,565	115	-	37,680	(24,623)	13,057
Current Risk Management Liabilities	23,806	239	-	24,045	(20,725)	3,320
Long-term Risk Management Liabilities	9,469	85	-	9,554	(5,854)	3,700
Total Liabilities	33,275	324	-	33,599	(26,579)	7,020
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,290	$ (209)	$ -	$ 4,081	$ 1,956	$ 6,037

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

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

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

The table below presents KPCo's activity of derivative risk management contracts for the three months ended March 31, 2013 and 2012:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2013 and 2012

Location of Gain (Loss)	**2013**	**2012**
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 596	$ (694)
Regulatory Assets (a)	-	12
Regulatory Liabilities (a)	(467)	1,059
Total Gain on Risk Management Contracts	$ 129	$ 377

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. 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 Expense on KPCo's condensed statements of income. During the three months ended March 31, 2013 and 2012, 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 (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory

Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2013 and 2012, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three months ended March 31, 2013 and 2012, 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 (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2013 and 2012, 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 (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2013 and 2012, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2013 and 2012, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2013 and 2012, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of March 31, 2013 and December 31, 2012 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
March 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 207	$ -	$ 207
Hedging Liabilities (a)	93	-	93
AOCI Gain (Loss) Net of Tax	76	(267)	(191)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	77	(60)	17

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

	Commodity	Interest Rate	Total
		(in thousands)	
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)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2013, 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 21 months.

Credit Risk

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

When AEPSC, on behalf of KPCo, uses standardized master agreements, AEPSC 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 March 31, 2013 and December 31, 2012:

	March 31, 2013	December 31, 2012
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 284	$ 432
Amount of Collateral KPCo Would Have Been Required to Post	749	741
Amount Attributable to RTO and ISO Activities	727	703

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of March 31, 2013 and December 31, 2012:

	March 31, 2013	December 31, 2012
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 6,722	$ 9,907
Amount of Cash Collateral Posted	-	365
Additional Settlement Liability if Cross Default Provision is Triggered	4,213	6,041

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The 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. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo's Long-term Debt as of March 31, 2013 and December 31, 2012 are summarized in the following table:

	March 31, 2013		December 31, 2012	
	Book Value	**Fair Value**	**Book Value**	**Fair Value**
	(in thousands)			
Long-term Debt	$ 549,264	$ 700,888	$ 549,222	$ 708,566

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2013 and December 31, 2012. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
March 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 656	$ 21,803	$ 2,724	$ (15,819)	$ 9,364
Cash Flow Hedges:					
Commodity Hedges (a)	-	272	-	(65)	207
Total Risk Management Assets	$ 656	$ 22,075	$ 2,724	$ (15,884)	$ 9,571
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 317	$ 20,128	$ 920	$ (16,448)	$ 4,917
Cash Flow Hedges:					
Commodity Hedges (a)	-	158	-	(65)	93
Total Risk Management Liabilities	$ 317	$ 20,286	$ 920	$ (16,513)	$ 5,010

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

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

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

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2013 and 2012.

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

Three Months Ended March 31, 2013	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(297)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	55
Transfers into Level 3 (d) (e)	126
Transfers out of Level 3 (e) (f)	(107)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(172)
Balance as of March 31, 2013	$ 1,804

Three Months Ended March 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)	(746)
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	10
Purchases, Issuances and Settlements (c)	1,229
Transfers into Level 3 (d) (e)	503
Transfers out of Level 3 (e) (f)	(802)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	989
Balance as of March 31, 2012	$ 1,599

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

The following table quantifies the significant unobservable inputs used in developing the fair value of Level 3 positions as of March 31, 2013:

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 2,544	$ 635	Discounted Cash Flow	Forward Market Price	$ 11.59	$ 75.95
FTRs	180	285	Discounted Cash Flow	Forward Market Price	(4.47)	9.67
Total	$ 2,724	$ 920				

(a) Represents market prices in dollars per MWh.

9. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

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 and 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.

10. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2013.

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.

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 of the AEP System Utility Money Pool agreement filed with FERC. The amount of outstanding borrowings from the Utility Money Pool as of March 31, 2013 and December 31, 2012 is included in Advances from Affiliates on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2013 are described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of March 31, 2013	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 32,649	$ 3,930	$ 12,095	$ 1,909	$ 11,039	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the three months ended March 31, 2013 and 2012 are summarized in the following table:

Three Months Ended March 31,	Maximum Interest Rate for Funds Borrowed from Utility Money Pool	Minimum Interest Rate for Funds Borrowed from Utility Money Pool	Maximum Interest Rate for Funds Loaned to Utility Money Pool	Minimum Interest Rate for Funds Loaned to Utility Money Pool	Average Interest Rate for Funds Borrowed from Utility Money Pool	Average Interest Rate for Funds Loaned to Utility Money Pool
2013	0.43 %	0.35 %	0.36 %	0.36 %	0.38 %	0.36 %
2012	- %	- %	0.56 %	0.45 %	- %	0.51 %

Sale of Receivables – AEP Credit

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

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $46 million for each of the periods ended March 31, 2013 and December 31, 2012, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended March 31, 2013 and 2012 were $520 thousand and $728 thousand, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended March 31, 2013 and 2012 were $140 million and $151 million, respectively.

11. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended March 31, 2013 and 2012 were $7 million and $7 million, respectively. The carrying amount of liabilities associated with AEPSC as of March 31, 2013 and December 31, 2012 was $3 million and $6 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1 and leases a 50% interest in Rockport Plant Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended March 31, 2013 and 2012 were $25 million and $25 million, respectively. The carrying amount of liabilities associated with AEGCo as of March 31, 2013 and December 31, 2012 was $8 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

12. 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 facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was 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 of $1.7 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the three months ended March 31, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of March 31, 2013
		(in thousands)			
$ 497	$ 214	$ -	$ (310)	$ (400)	$ 1

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. The remaining liability is included in Other Current Liabilities on the condensed balance sheets. Management does not expect additional costs to be incurred related to this initiative.

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Kentucky Power Company

2013 Second Quarter Report

Financial Statements

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
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.
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
REVENUES				
Electric Generation, Transmission and Distribution	$ 140,087	$ 130,385	$ 306,505	$ 289,188
Sales to AEP Affiliates	9,176	9,629	23,730	14,654
Other Revenues	150	103	282	305
TOTAL REVENUES	149,413	140,117	330,517	304,147
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	25,034	26,610	68,755	56,595
Purchased Electricity for Resale	2,940	3,107	6,310	7,101
Purchased Electricity from AEP Affiliates	60,411	43,498	118,075	99,526
Other Operation	13,590	14,158	26,857	28,501
Maintenance	11,959	6,985	23,655	25,779
Depreciation and Amortization	14,205	13,628	28,871	27,169
Taxes Other Than Income Taxes	3,239	3,054	6,374	6,247
TOTAL EXPENSES	131,378	111,040	278,897	250,918
OPERATING INCOME	18,035	29,077	51,620	53,229
Other Income (Expense):				
Interest Income	217	93	244	215
Allowance for Equity Funds Used During Construction	404	803	665	1,502
Interest Expense	(8,799)	(8,899)	(17,684)	(17,664)
INCOME BEFORE INCOME TAX EXPENSE	9,857	21,074	34,845	37,282
Income Tax Expense	3,245	6,339	11,471	11,529
NET INCOME	$ 6,612	$ 14,735	$ 23,374	$ 25,753

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
Net Income	$ 6,612	$ 14,735	$ 23,374	$ 25,753
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $12 and $32 for the Three Months Ended June 30, 2013 and 2012, Respectively, and $106 and $33 for the Six Months Ended June 30, 2013 and 2012, Respectively	(22)	60	196	(61)
TOTAL COMPREHENSIVE INCOME	$ 6,590	$ 14,795	$ 23,570	$ 25,692

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2013 and 2012
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 50,450	$ 238,750	$ 171,841	$ (625)	$ 460,416
Common Stock Dividends			(16,000)		(16,000)
Net Income			25,753		25,753
Other Comprehensive Loss				(61)	(61)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2012	$ 50,450	$ 238,750	$ 181,594	$ (686)	$ 470,108
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 50,450	$ 238,750	$ 190,819	$ (409)	$ 479,610
Common Stock Dividends			(12,500)		(12,500)
Net Income			23,374		23,374
Other Comprehensive Income				196	196
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2013	$ 50,450	$ 238,750	$ 201,693	$ (213)	$ 490,680

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2013 and December 31, 2012
(in thousands)
(Unaudited)

	June 30, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,046	$ 1,482
Advances to Affiliates	4,600	-
Accounts Receivable:		
Customers	16,766	15,666
Affiliated Companies	7,168	10,152
Accrued Unbilled Revenues	320	817
Miscellaneous	259	151
Allowance for Uncollectible Accounts	(19)	(142)
Total Accounts Receivable	24,494	26,644
Fuel	47,193	69,147
Materials and Supplies	21,406	25,061
Risk Management Assets	5,937	6,175
Accrued Tax Benefits	7,270	5,186
Prepayments and Other Current Assets	3,852	6,626
TOTAL CURRENT ASSETS	115,798	140,321
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	560,292	558,935
Transmission	491,243	490,152
Distribution	670,752	652,615
Other Property, Plant and Equipment	62,914	63,151
Construction Work in Progress	49,072	44,281
Total Property, Plant and Equipment	1,834,273	1,809,134
Accumulated Depreciation and Amortization	622,022	603,373
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,212,251	1,205,761
OTHER NONCURRENT ASSETS		
Regulatory Assets	212,542	213,734
Long-term Risk Management Assets	4,864	6,882
Deferred Charges and Other Noncurrent Assets	43,788	48,880
TOTAL OTHER NONCURRENT ASSETS	261,194	269,496
TOTAL ASSETS	$ 1,589,243	$ 1,615,578

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2013 and December 31, 2012
(Unaudited)

	June 30, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 13,359
Accounts Payable:		
General	19,464	30,337
Affiliated Companies	30,369	40,965
Risk Management Liabilities	2,822	3,320
Customer Deposits	24,616	23,485
Accrued Taxes	11,239	11,818
Accrued Interest	6,598	7,210
Regulatory Liability for Over-Recovered Fuel Costs	1,573	7,928
Other Current Liabilities	21,587	25,685
TOTAL CURRENT LIABILITIES	118,268	164,107
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	529,305	529,222
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,886	3,700
Deferred Income Taxes	361,552	353,578
Regulatory Liabilities and Deferred Investment Tax Credits	25,433	26,159
Employee Benefits and Pension Obligations	32,546	30,981
Deferred Credits and Other Noncurrent Liabilities	8,573	8,221
TOTAL NONCURRENT LIABILITIES	980,295	971,861
TOTAL LIABILITIES	1,098,563	1,135,968
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	238,750
Retained Earnings	201,693	190,819
Accumulated Other Comprehensive Income (Loss)	(213)	(409)
TOTAL COMMON SHAREHOLDER'S EQUITY	490,680	479,610
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 1,589,243	$ 1,615,578

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2013 and 2012
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
OPERATING ACTIVITIES		
Net Income	$ 23,374	$ 25,753
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	28,871	27,169
Deferred Income Taxes	7,705	3,610
Net Recovery of (Deferral of) Storm Costs	2,349	(2,998)
Allowance for Equity Funds Used During Construction	(665)	(1,502)
Mark-to-Market of Risk Management Contracts	1,208	9
Property Taxes	5,418	5,193
Fuel Over/Under-Recovery, Net	(6,355)	(120)
Change in Other Noncurrent Assets	(3,736)	(6,723)
Change in Other Noncurrent Liabilities	1,545	1,940
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	2,330	11,275
Fuel, Materials and Supplies	25,609	(14,064)
Accounts Payable	(17,866)	(15,214)
Accrued Taxes, Net	(2,663)	(518)
Other Current Assets	2,596	1,148
Other Current Liabilities	(5,804)	(4,323)
Net Cash Flows from Operating Activities	63,916	30,635
INVESTING ACTIVITIES		
Construction Expenditures	(38,211)	(46,714)
Change in Advances to Affiliates, Net	(4,600)	32,337
Acquisitions of Assets	(55)	(7)
Proceeds from Sales of Assets	4,663	206
Net Cash Flows Used for Investing Activities	(38,203)	(14,178)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(13,359)	-
Principal Payments for Capital Lease Obligations	(524)	(612)
Dividends Paid on Common Stock	(12,500)	(16,000)
Other Financing Activities	234	13
Net Cash Flows Used for Financing Activities	(26,149)	(16,599)
Net Decrease in Cash and Cash Equivalents	(436)	(142)
Cash and Cash Equivalents at Beginning of Period	1,482	778
Cash and Cash Equivalents at End of Period	$ 1,046	$ 636
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 17,888	$ 17,827
Net Cash Paid for Income Taxes	5,969	6,401
Noncash Acquisitions Under Capital Leases	682	252
Construction Expenditures Included in Current Liabilities as of June 30,	5,975	7,457

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

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

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1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2013 is not necessarily indicative of results that may be expected for the year ending December 31, 2013. The condensed financial statements are unaudited and should be read in conjunction with the audited 2012 financial statements and notes thereto, which are included in KPCo's 2012 Annual Report.

Management reviewed subsequent events through July 26, 2013, the date that the second quarter 2013 report was issued.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and six months ended June 30, 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2013

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of March 31, 2013	$ 76	$ (267)	$ (191)
Change in Fair Value Recognized in AOCI	(22)	-	(22)
Amounts Reclassified from AOCI	(15)	15	-
Net Current Period Other Comprehensive Income	(37)	15	(22)
Balance in AOCI as of June 30, 2013	$ 39	$ (252)	$ (213)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2013

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (409)
Change in Fair Value Recognized in AOCI	139	-	139
Amounts Reclassified from AOCI	27	30	57
Net Current Period Other Comprehensive Income	166	30	196
Balance in AOCI as of June 30, 2013	$ 39	$ (252)	$ (213)

Reclassifications Out of Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and six months ended June 30, 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2013

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Commodity:	
Electric Generation, Transmission and Distribution Revenues	$ 12
Purchased Electricity for Resale	(30)
Other Operation Expense	(2)
Maintenance Expense	-
Property, Plant and Equipment	(2)
Subtotal - Commodity	(22)
Interest Rate and Foreign Currency:	
Interest Expense	23
Subtotal - Interest Rate and Foreign Currency	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	1
Income Tax (Expense) Credit	1
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ -

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2013

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Commodity:	
Electric Generation, Transmission and Distribution Revenues	$ 31
Purchased Electricity for Resale	24
Other Operation Expense	(5)
Maintenance Expense	(2)
Property, Plant and Equipment	(6)
Subtotal - Commodity	42
Interest Rate and Foreign Currency:	
Interest Expense	46
Subtotal - Interest Rate and Foreign Currency	46
Reclassifications from AOCI, before Income Tax (Expense) Credit	88
Income Tax (Expense) Credit	31
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 57

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2012. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended June 30, 2012

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of March 31, 2012	$ (419)	$ (327)	$ (746)
Changes in Fair Value Recognized in AOCI	(94)	-	(94)
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(3)	-	(3)
Purchased Electricity for Resale	149	-	149
Other Operation Expense	(3)	-	(3)
Maintenance Expense	(1)	-	(1)
Interest Expense	-	15	15
Property, Plant and Equipment	(3)	-	(3)
Balance in AOCI as of June 30, 2012	$ (374)	$ (312)	$ (686)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 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	(444)	-	(444)
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(3)	-	(3)
Purchased Electricity for Resale	365	-	365
Other Operation Expense	(3)	-	(3)
Maintenance Expense	(2)	-	(2)
Interest Expense	-	30	30
Property, Plant and Equipment	(4)	-	(4)
Balance in AOCI as of June 30, 2012	$ (374)	$ (312)	$ (686)

3. RATE MATTERS

As discussed in KPCo's 2012 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2012 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2013 and updates KPCo's 2012 Annual Report.

Regulatory Assets Not Yet Being Recovered

Noncurrent Regulatory Assets	June 30, 2013	December 31, 2012
	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 12,146	$ 12,146
Mountaineer Carbon Capture and Storage Commercial Scale Facility	873	873
Total Regulatory Assets Not Yet Being Recovered	$ 13,019	$ 13,019

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

Plant Transfer

In October 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. KPCo also requested costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. KPCo is currently seeking recovery of these costs with the KPSC. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace the capacity from the retirement of Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC. As of June 30, 2013, KPCo has incurred $28 million related to the FGD project, which is recorded in Deferred Charges and Other Noncurrent Assets on the balance sheet.

In May 2013, a memorandum of understanding (MOU) between KPCo, KIUC and the Sierra Club was filed with the KPSC. The MOU includes (a) the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 (b) the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, (c) the authorization to record FGD project costs as a regulatory asset, (d) the conversion of Big Sandy Plant, Unit 1 to natural gas and (e) any off-system sales margins above the $15.3 million annual level in base rates be retained by KPCo. In July 2013, KPCo, KIUC and the Sierra Club filed a settlement agreement with the KPSC pursuant to the MOU as modified. The settlement agreement also addressed potential greenhouse gas initiatives on the Mitchell Plant. The Attorney General was not a party to the settlement agreement. If approved, KPCo will withdraw the current base rate case request and current rates will remain in effect until at least May 2015. Hearings were held at the KPSC in July 2013. If KPCo is not ultimately permitted to recover its incurred costs, it could reduce future net income and cash flows and impact financial condition.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase includes cost recovery of the pending transfer of the one-half interest in the Mitchell Plant (780 MW) and cost recovery of Big Sandy Plant, Units 1 and 2. The filing also includes requests for recovery of deferrals totaling $48 million including $28 million related to the Big Sandy Plant FGD project and $12 million related to 2012 storm costs which are recorded in Deferred Charges and Other Noncurrent Assets and Regulatory Assets, respectively, on the balance sheet. Additionally, KPCo proposed that Big Sandy Plant, Unit 2 expenses incurred over the period January 2014 through May 2015 be deferred and recovered over five years beginning January 2014. Also in June 2013, a settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club was filed with the KPSC which supported the Mitchell plant transfer discussed above. If the settlement agreement is approved, KPCo will withdraw this base rate case request and current rates will remain in effect until at least May 2015. If KPCo is not ultimately permitted to recover its incurred costs, it could reduce future net income and cash flows and impact financial condition.

FERC Rate Matters

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 and to transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). This transfer is proposed to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AEPGenCo and the Mitchell Plant assets to APCo and KPCo. In May 2013, the IEU petitioned the FERC for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AEPGenCo. This issue remains pending before the FERC.

Additionally, the AEP East Companies requested FERC approval, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, KPCo would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision is pending at the FERC. Similar filings have been made at the KPSC. See the "Plant Transfer" section of Rate Matters.

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.

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. The Commitments, Guarantees and Contingencies note within KPCo's 2012 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of June 30, 2013, 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 conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of June 30, 2013, the maximum potential loss for these lease agreements was approximately $1.1 million assuming the fair value of the equipment is zero at the end of the lease term.

CONTINGENCIES

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. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court's dismissal of the complaint. The plaintiffs may seek further review in the U.S. Supreme Court. 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. 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 filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

5. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans for the three and six months ended June 30, 2013 and 2012:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	$ 258	$ 353	$ 112	$ 251
Interest Cost	1,235	1,366	458	709
Expected Return on Plan Assets	(1,605)	(1,848)	(738)	(728)
Amortization of Prior Service Cost (Credit)	11	21	(505)	(126)
Amortization of Net Actuarial Loss	1,117	920	421	392
Net Periodic Benefit Cost (Credit)	$ 1,016	$ 812	$ (252)	$ 498

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	$ 515	$ 706	$ 223	$ 503
Interest Cost	2,470	2,732	916	1,418
Expected Return on Plan Assets	(3,210)	(3,696)	(1,475)	(1,456)
Amortization of Prior Service Cost (Credit)	21	42	(1,010)	(252)
Amortization of Net Actuarial Loss	2,235	1,839	842	784
Net Periodic Benefit Cost (Credit)	$ 2,031	$ 1,623	$ (504)	$ 997

6. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated 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 the KPCo's outstanding derivative contracts as of June 30, 2013 and December 31, 2012:

Notional Volume of Derivative Instruments

	Volume		
	June 30, 2013	**December 31, 2012**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	20,536	18,838	MWhs
Coal	148	247	Tons
Natural Gas	1,261	2,018	MMBtus
Heating Oil and Gasoline	216	269	Gallons
Interest Rate	$ 3,734	$ 4,836	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 condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2013 and December 31, 2012 condensed balance sheets, KPCo netted \$114 thousand and \$253 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and \$1.0 million and \$2.2 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 KPCo's derivative activity on the condensed balance sheets as of June 30, 2013 and December 31, 2012:

Fair Value of Derivative Instruments
June 30, 2013

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 18,158	$ 205	$ -	$ 18,363	$ (12,426)	$ 5,937
Long-term Risk Management Assets	7,946	-	-	7,946	(3,082)	4,864
Total Assets	26,104	205	-	26,309	(15,508)	10,801
Current Risk Management Liabilities	15,811	143	-	15,954	(13,132)	2,822
Long-term Risk Management Liabilities	6,179	6	-	6,185	(3,299)	2,886
Total Liabilities	21,990	149	-	22,139	(16,431)	5,708
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,114	$ 56	$ -	$ 4,170	$ 923	$ 5,093

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 25,448	$ 72	$ -	$ 25,520	$ (19,345)	$ 6,175
Long-term Risk Management Assets	12,117	43	-	12,160	(5,278)	6,882
Total Assets	37,565	115	-	37,680	(24,623)	13,057
Current Risk Management Liabilities	23,806	239	-	24,045	(20,725)	3,320
Long-term Risk Management Liabilities	9,469	85	-	9,554	(5,854)	3,700
Total Liabilities	33,275	324	-	33,599	(26,579)	7,020
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,290	$ (209)	$ -	$ 4,081	$ 1,956	$ 6,037

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

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

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

The table below presents KPCo's activity of derivative risk management contracts for the three and six months ended June 30, 2013 and 2012:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Six Months Ended June 30, 2013 and 2012

Location of Gain (Loss)	Three Months Ended June 30, 2013	Three Months Ended June 30, 2012	Six Months Ended June 30, 2013	Six Months Ended June 30, 2012
	(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ (150)	$ (877)	$ 446	$ (1,571)
Regulatory Assets (a)	-	(3)	-	9
Regulatory Liabilities (a)	298	858	(169)	1,917
Total Gain (Loss) on Risk Management Contracts	$ 148	$ (22)	$ 277	$ 355

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. 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 Expense on KPCo's condensed statements of income. During the three and six months ended June 30, 2013 and 2012, 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 (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2013 and 2012, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three and six months ended June 30, 2013 and 2012, 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 (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2013 and 2012, 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 (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and six months ended June 30, 2013 and 2012, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During the three and six months ended June 30, 2013 and 2012, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2013 and 2012, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of June 30, 2013 and December 31, 2012 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
June 30, 2013

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ 117	$ -	$ 117
Hedging Liabilities (a)	61	-	61
AOCI Gain (Loss) Net of Tax	39	(252)	(213)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	43	(60)	(17)

Impact of Cash Flow Hedges on the Condensed 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)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of June 30, 2013, 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 18 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (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 June 30, 2013 and December 31, 2012:

	June 30, 2013	December 31, 2012
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 193	$ 432
Amount of Collateral KPCo Would Have Been Required to Post	1,267	741
Amount Attributable to RTO and ISO Activities	1,252	703

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of June 30, 2013 and December 31, 2012:

	June 30, 2013	December 31, 2012
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 6,583	$ 9,907
Amount of Cash Collateral Posted	-	365
Additional Settlement Liability if Cross Default Provision is Triggered	5,099	6,041

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for “Fair Value Measurements and Disclosures” establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The 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. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo’s Long-term Debt as of June 30, 2013 and December 31, 2012 are summarized in the following table:

	June 30, 2013		December 31, 2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 549,305	$ 658,719	$ 549,222	$ 708,566

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2013 and December 31, 2012. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 526	$ 22,346	$ 3,199	$ (15,387)	$ 10,684
Cash Flow Hedges:					
Commodity Hedges (a)	-	205	-	(88)	117
Total Risk Management Assets	$ 526	$ 22,551	$ 3,199	$ (15,475)	$ 10,801
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 304	$ 21,128	$ 525	$ (16,310)	$ 5,647
Cash Flow Hedges:					
Commodity Hedges (a)	-	149	-	(88)	61
Total Risk Management Liabilities	$ 304	$ 21,277	$ 525	$ (16,398)	$ 5,708

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

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

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

There were no transfers between Level 1 and Level 2 during the three and six months ended June 30, 2013 and 2012.

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

Three Months Ended June 30, 2013	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of March 31, 2013	$ 1,804
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(76)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	132
Transfers into Level 3 (d) (e)	50
Transfers out of Level 3 (e) (f)	(75)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	839
Balance as of June 30, 2013	$ 2,674

Three Months Ended June 30, 2012	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of March 31, 2012	$ 1,599
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(643)
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	(2)
Purchases, Issuances and Settlements (c)	999
Transfers into Level 3 (d) (e)	261
Transfers out of Level 3 (e) (f)	(112)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	475
Balance as of June 30, 2012	$ 2,577

Six Months Ended June 30, 2013	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(725)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	591
Transfers into Level 3 (d) (e)	177
Transfers out of Level 3 (e) (f)	(191)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	623
Balance as of June 30, 2013	$ 2,674

Six Months Ended June 30, 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)	(1,100)
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	11
Purchases, Issuances and Settlements (c)	2,367
Transfers into Level 3 (d) (e)	743
Transfers out of Level 3 (e) (f)	(984)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	1,124
Balance as of June 30, 2012	$ 2,577

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

The following table quantifies the significant unobservable inputs used in developing the fair value of Level 3 positions as of June 30, 2013:

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	**Liabilities**	**Technique**	**Unobservable Input (a)**	**Low**	**High**
	(in thousands)					
Energy Contracts	$ 2,436	$ 332	Discounted Cash Flow	Forward Market Price	$ 11.48	$ 70.90
FTRs	763	193	Discounted Cash Flow	Forward Market Price	(12.31)	11.19
Total	$ 3,199	$ 525				

(a) Represents market prices in dollars per MWh.

9. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. The completion of the federal audit did not result in a material impact on net income, cash flows or financial condition. 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 and 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. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2008.

10. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first six months of 2013.

In July 2013, AEPGenCo, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. Under the credit facility, OPCo may assign borrowings to AEPGenCo upon the transfer of OPCo's generation assets to AEPGenCo. Subject to regulatory approval, AEPGenCo may further assign a portion of the borrowings to APCo and KPCo, not to exceed $500 million and $250 million, respectively, upon AEPGenCo's subsequent transfer of certain of those generation assets to APCo and KPCo.

Dividend Restrictions

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

Federal Power Act

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

Leverage Restrictions

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

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of June 30, 2013 and December 31, 2012 are included in Advances to Affiliates and Advances from Affiliates, respectively, on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the six months ended June 30, 2013 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Loans to the Utility Money Pool as of June 30, 2013	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 32,649	$ 27,164	$ 11,271	$ 14,234	$ 4,600	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the six months ended June 30, 2013 and 2012 are summarized in the following table:

Six Months Ended June 30,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2013	0.43 %	0.35 %	0.36 %	0.32 %	0.38 %	0.34 %
2012	- %	- %	0.56 %	0.45 %	- %	0.49 %

Sale of Receivables – AEP Credit

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

In June 2013, AEP Credit amended its receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. AEP Credit amended a commitment of $385 million to now expire in June 2014. 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 $41 million and $46 million as of June 30, 2013 and December 31, 2012, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended June 30, 2013 and 2012 were $481 thousand and $597 thousand, respectively, and for the six months ended June 30, 2013 and 2012 were $1 million and $1.3 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended June 30, 2013 and 2012 were $128 million and $114 million, respectively, and for the six months ended June 30, 2013 and 2012 were $268 million and $265 million, respectively.

11. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP’s subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC’s cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC’s cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo’s total billings from AEPSC for the three months ended June 30, 2013 and 2012 were both $8 million and for the six months ended June 30, 2013 and 2012 were both $15 million. The carrying amount of liabilities associated with AEPSC as of June 30, 2013 and December 31, 2012 was $2 million and $6 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management’s control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended June 30, 2013 and 2012 were both $23 million and for the six months ended June 30, 2013 and 2012 were both $48 million. The carrying amount of liabilities associated with AEGCo as of June 30, 2013 and December 31, 2012 was $8 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

12. 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 facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was 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 of $1.7 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the six months ended June 30, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of June 30, 2013
		(in thousands)			
$ 497	$ 230	$ -	$ (327)	$ (400)	$ -

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. Management does not expect additional costs to be incurred related to this initiative.

Kentucky Power Company

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., an electric utility holding company.
AEP Credit	AEP Credit, Inc., a consolidated variable interest entity of AEP which securitizes accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East Companies	APCo, I&M, KPCo and OPCo.
AEP System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEPSC	American Electric Power Service Corporation, an AEP service subsidiary providing management and professional services to AEP and its subsidiaries.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CO_2	Carbon dioxide and other greenhouse gases.
CWIP	Construction Work in Progress.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MW	Megawatt.
MWh	Megawatthour.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana. AEGCo and I&M jointly-own Unit 1. In 1989, AEGCo and I&M entered into a sale-and-leaseback transaction with Wilmington Trust Company, an unrelated, unconsolidated trustee for Rockport Plant, Unit 2.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.

Term	Meaning
Utility Money Pool	Centralized funding mechanism AEP uses to meet the short-term cash requirements of certain utility subsidiaries.
VIE	Variable Interest Entity.
WVPSC	Public Service Commission of West Virginia.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
REVENUES				
Electric Generation, Transmission and Distribution	$ 151,970	$ 147,067	$ 458,475	$ 436,255
Sales to AEP Affiliates	12,018	16,394	35,748	31,048
Other Revenues	171	149	453	454
TOTAL REVENUES	164,159	163,610	494,676	467,757
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	17,623	34,624	86,378	91,219
Purchased Electricity for Resale	2,523	2,291	8,833	9,392
Purchased Electricity from AEP Affiliates	79,881	57,781	197,956	157,307
Other Operation	15,909	14,264	42,766	42,765
Maintenance	14,310	8,650	37,965	34,429
Asset Impairments and Other Related Charges	32,847	-	32,847	-
Depreciation and Amortization	14,322	13,761	43,193	40,930
Taxes Other Than Income Taxes	3,482	3,115	9,856	9,362
TOTAL EXPENSES	180,897	134,486	459,794	385,404
OPERATING INCOME (LOSS)	(16,738)	29,124	34,882	82,353
Other Income (Expense):				
Interest Income	45	81	289	296
Allowance for Equity Funds Used During Construction	511	474	1,176	1,976
Interest Expense	(8,699)	(8,750)	(26,383)	(26,414)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (CREDIT)	(24,881)	20,929	9,964	58,211
Income Tax Expense (Credit)	(8,899)	6,719	2,572	18,248
NET INCOME (LOSS)	$ (15,982)	$ 14,210	$ 7,392	$ 39,963

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

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2013 and 2012
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
Net Income (Loss)	$ (15,982)	$ 14,210	$ 7,392	$ 39,963
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $17 and $172 for the Three Months Ended September 30, 2013 and 2012, Respectively, and $89 and $139 for the Nine Months Ended September 30, 2013 and 2012, Respectively	(31)	320	165	259
TOTAL COMPREHENSIVE INCOME (LOSS)	$ (16,013)	$ 14,530	$ 7,557	$ 40,222

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2013 and 2012
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2011	$ 50,450	$ 238,750	$ 171,841	$ (625)	$ 460,416
Common Stock Dividends			(24,000)		(24,000)
Net Income			39,963		39,963
Other Comprehensive Income				259	259
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2012	$ 50,450	$ 238,750	$ 187,804	$ (366)	$ 476,638
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 50,450	$ 238,750	$ 190,819	$ (409)	$ 479,610
Common Stock Dividends			(18,750)		(18,750)
Net Income			7,392		7,392
Other Comprehensive Income				165	165
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2013	$ 50,450	$ 238,750	$ 179,461	$ (244)	$ 468,417

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2013 and December 31, 2012
(in thousands)
(Unaudited)

	September 30, 2013	December 31, 2012
CURRENT ASSETS		
Cash and Cash Equivalents	$ 845	$ 1,482
Advances to Affiliates	6,300	-
Accounts Receivable:		
Customers	7,350	15,666
Affiliated Companies	10,066	10,152
Accrued Unbilled Revenues	49	817
Miscellaneous	254	151
Allowance for Uncollectible Accounts	(69)	(142)
Total Accounts Receivable	17,650	26,644
Fuel	54,324	69,147
Materials and Supplies	20,259	25,061
Risk Management Assets	5,042	6,175
Accrued Tax Benefits	6,928	5,186
Prepayments and Other Current Assets	4,213	6,626
TOTAL CURRENT ASSETS	115,561	140,321
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	560,511	558,935
Transmission	491,310	490,152
Distribution	678,308	652,615
Other Property, Plant and Equipment	64,423	63,151
Construction Work in Progress	57,588	44,281
Total Property, Plant and Equipment	1,852,140	1,809,134
Accumulated Depreciation and Amortization	633,086	603,373
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,219,054	1,205,761
OTHER NONCURRENT ASSETS		
Regulatory Assets	203,120	213,734
Long-term Risk Management Assets	4,294	6,882
Deferred Charges and Other Noncurrent Assets	8,240	48,880
TOTAL OTHER NONCURRENT ASSETS	215,654	269,496
TOTAL ASSETS	$ 1,550,269	$ 1,615,578

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2013 and December 31, 2012
(Unaudited)

	September 30, 2013	December 31, 2012
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 13,359
Accounts Payable:		
General	18,893	30,337
Affiliated Companies	29,565	40,965
Risk Management Liabilities	2,383	3,320
Customer Deposits	24,769	23,485
Accrued Taxes	11,477	11,818
Accrued Interest	5,598	7,210
Regulatory Liability for Over-Recovered Fuel Costs	5,582	7,928
Other Current Liabilities	18,567	25,685
TOTAL CURRENT LIABILITIES	116,834	164,107
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	529,347	529,222
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,489	3,700
Deferred Income Taxes	350,446	353,578
Regulatory Liabilities and Deferred Investment Tax Credits	24,195	26,159
Employee Benefits and Pension Obligations	29,709	30,981
Deferred Credits and Other Noncurrent Liabilities	8,832	8,221
TOTAL NONCURRENT LIABILITIES	965,018	971,861
TOTAL LIABILITIES	1,081,852	1,135,968
Rate Matters (Note 3)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	238,750
Retained Earnings	179,461	190,819
Accumulated Other Comprehensive Income (Loss)	(244)	(409)
TOTAL COMMON SHAREHOLDER'S EQUITY	468,417	479,610
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 1,550,269	$ 1,615,578

See Condensed Notes to Condensed Financial Statements beginning on page 9.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2013 and 2012
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2013	2012
OPERATING ACTIVITIES		
Net Income	$ 7,392	$ 39,963
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	43,193	40,930
Deferred Income Taxes	(4,223)	6,947
Asset Impairments and Other Related Charges	32,847	-
Net Recovery of (Deferral of) Storm Costs	3,524	(9,159)
Allowance for Equity Funds Used During Construction	(1,176)	(1,976)
Mark-to-Market of Risk Management Contracts	1,756	2,531
Property Taxes	7,921	7,612
Fuel Over/Under-Recovery, Net	(2,346)	(1,009)
Change in Other Noncurrent Assets	(3,490)	(6,618)
Change in Other Noncurrent Liabilities	2,218	128
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	9,174	2,955
Fuel, Materials and Supplies	19,625	(15,131)
Accounts Payable	(20,256)	(4,669)
Accrued Taxes, Net	(1,073)	(101)
Other Current Assets	2,233	866
Other Current Liabilities	(6,772)	(2,321)
Net Cash Flows from Operating Activities	90,547	60,948
INVESTING ACTIVITIES		
Construction Expenditures	(56,905)	(73,536)
Change in Advances to Affiliates, Net	(6,300)	36,596
Acquisitions of Assets	(63)	(19)
Proceeds from Sales of Assets	4,764	619
Net Cash Flows Used for Investing Activities	(58,504)	(36,340)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	(13,359)	-
Principal Payments for Capital Lease Obligations	(813)	(921)
Dividends Paid on Common Stock	(18,750)	(24,000)
Other Financing Activities	242	24
Net Cash Flows Used for Financing Activities	(32,680)	(24,897)
Net Decrease in Cash and Cash Equivalents	(637)	(289)
Cash and Cash Equivalents at Beginning of Period	1,482	778
Cash and Cash Equivalents at End of Period	$ 845	$ 489
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 27,397	$ 27,369
Net Cash Paid for Income Taxes	7,703	9,373
Noncash Acquisitions Under Capital Leases	881	412
Construction Expenditures Included in Current Liabilities as of September 30,	6,952	6,838

See Condensed Notes to Condensed Financial Statements beginning on page 9.

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2013 is not necessarily indicative of results that may be expected for the year ending December 31, 2013. The condensed financial statements are unaudited and should be read in conjunction with the audited 2012 financial statements and notes thereto, which are included in KPCo's 2012 Annual Report.

Management reviewed subsequent events through October 25, 2013, the date that the third quarter 2013 report was issued.

2. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and nine months ended September 30, 2013. All amounts in the following tables are presented net of related income taxes.

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of June 30, 2013	$ 39	$ (252)	$ (213)
Change in Fair Value Recognized in AOCI	(7)	-	(7)
Amounts Reclassified from AOCI	(39)	15	(24)
Net Current Period Other Comprehensive Income	(46)	15	(31)
Balance in AOCI as of September 30, 2013	$ (7)	$ (237)	$ (244)

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges		
	Commodity	Interest Rate and Foreign Currency	Total
		(in thousands)	
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (409)
Change in Fair Value Recognized in AOCI	132	-	132
Amounts Reclassified from AOCI	(12)	45	33
Net Current Period Other Comprehensive Income	120	45	165
Balance in AOCI as of September 30, 2013	$ (7)	$ (237)	$ (244)

Reclassifications Out of Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and nine months ended September 30, 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2013

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Commodity:	
Electric Generation, Transmission and Distribution Revenues	$ (70)
Purchased Electricity for Resale	20
Other Operation Expense	(3)
Maintenance Expense	(3)
Property, Plant and Equipment	(4)
Subtotal - Commodity	(60)
Interest Rate and Foreign Currency:	
Interest Expense	23
Subtotal - Interest Rate and Foreign Currency	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	(37)
Income Tax (Expense) Credit	(13)
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (24)

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2013

Gains and Losses on Cash Flow Hedges	Amount of (Gain) Loss Reclassified from AOCI (in thousands)
Commodity:	
Electric Generation, Transmission and Distribution Revenues	$ (39)
Purchased Electricity for Resale	44
Other Operation Expense	(8)
Maintenance Expense	(5)
Property, Plant and Equipment	(10)
Subtotal - Commodity	(18)
Interest Rate and Foreign Currency:	
Interest Expense	69
Subtotal - Interest Rate and Foreign Currency	69
Reclassifications from AOCI, before Income Tax (Expense) Credit	51
Income Tax (Expense) Credit	18
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 33

The following tables provide details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on the condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2012. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Three Months Ended September 30, 2012

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of June 30, 2012	$ (374)	$ (312)	$ (686)
Changes in Fair Value Recognized in AOCI	273	-	273
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(4)	-	(4)
Purchased Electricity for Resale	33	-	33
Other Operation Expense	(1)	-	(1)
Maintenance Expense	3	-	3
Interest Expense	-	15	15
Property, Plant and Equipment	1	-	1
Balance in AOCI as of September 30, 2012	$ (69)	$ (297)	$ (366)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 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	(171)	-	(171)
Amount of (Gain) or Loss Reclassified from AOCI			
to Statement of Income/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(7)	-	(7)
Purchased Electricity for Resale	398	-	398
Other Operation Expense	(4)	-	(4)
Maintenance Expense	1	-	1
Interest Expense	-	45	45
Property, Plant and Equipment	(3)	-	(3)
Balance in AOCI as of September 30, 2012	$ (69)	$ (297)	$ (366)

3. RATE MATTERS

As discussed in KPCo's 2012 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2012 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2013 and updates KPCo's 2012 Annual Report.

Regulatory Assets Not Yet Being Recovered

Noncurrent Regulatory Assets	September 30, 2013	December 31, 2012
	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 12,146	$ 12,146
Mountaineer Carbon Capture and Storage Commercial Scale Facility	-	873
Total Regulatory Assets Not Yet Being Recovered	$ 12,146	$ 13,019

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

Plant Transfer

In October 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. KPCo also requested costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of September 30, 2013, the net book value of Big Sandy, Unit 2 was $251 million, before cost of removal, including materials and supplies inventory and CWIP. KPCo is currently seeking recovery of these costs with the KPSC. In March 2013, KPCo issued a Request for Proposal (RFP) to purchase up to 250 MW of long-term capacity and energy to replace a portion of the capacity from the retirement of Big Sandy Plant, Unit 1. In June 2013, KPCo filed the results of its RFP with the KPSC.

In July 2013, KPCo, Kentucky Industrial Utility Customers, Inc. (KIUC) and the Sierra Club filed a settlement agreement with the KPSC. The settlement included the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up. The settlement also allows KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement included the authorization to record FGD project costs as a regulatory asset, the conversion of Big Sandy Plant, Unit 1 to natural gas and addressed potential greenhouse gas initiatives on the Mitchell Plant. In October 2013, the KPSC issued an order approving a modified settlement agreement that included a limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order, which is currently pending. Additionally, the order rejected KPCo's request to defer FGD project costs for Big Sandy, Unit 2. Also in October 2013, KPCo filed with the KPSC accepting and agreeing to be bound by the modifications to the settlement agreement. As a result of this order, in the third quarter of 2013, KPCo recorded a pretax impairment of $33 million in Asset Impairments and Other Related Charges on the statement of income.

2013 Kentucky Base Rate Case

In June 2013, KPCo filed a request with the KPSC for an annual increase in base rates of $114 million based upon a return on common equity of 10.65% to be effective January 2014. The proposed revenue increase includes cost recovery of the pending transfer of the one-half interest in the Mitchell Plant (780 MW). In October 2013, the KPSC issued an order which modified and approved a settlement agreement relating to the proposed transfer of the one-half interest in the Mitchell Plant, in which KPCo agreed to withdraw this base rate case request. KPCo intends to withdraw this base rate request following the resolution of any potential requests for rehearing or appeals of the KPSC order. Assuming KPCo withdraws the base rate case, current base rates will remain in effect until at least May 2015.

FERC Rate Matters

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 and to transfer at net book value OPCo's Mitchell Plant to APCo and KPCo in equal one-half interests (780 MW each). This transfer is proposed to be effective December 31, 2013. In April 2013, the FERC issued orders approving the transfer of OPCo's generation assets to AEP Generation Resources Inc. (AEPGenCo), a nonregulated AEP subsidiary in the Generation and Marketing segment, and the Mitchell Plant assets to APCo and KPCo. In May 2013, the Industry Energy Users-Ohio petitioned the FERC for rehearing of its order granting OPCo authority to implement corporate separation by transferring its generation assets to AEPGenCo. This issue remains pending before the FERC. Similar filings have been made at the KPSC. See the "Plant Transfer" section of Rate Matters.

Additionally, the AEP East Companies requested FERC approval, effective January 1, 2014, to terminate the existing Interconnection Agreement and approve a Power Coordination Agreement (PCA) among APCo, I&M and KPCo with AEPSC as the agent to coordinate their respective power supply resources. Under the PCA, KPCo would be individually responsible for planning its respective capacity obligations and there would be no capacity equalization charges/credits on deficit/surplus companies. Further, the PCA allows, but does not obligate, KPCo to participate collectively under a common fixed resource requirement capacity plan in PJM and to participate in specified collective off-system sales and purchase activities. Intervenors have opposed several of these filings. The AEP East Companies responded to intervenor comments and filed a revised PCA at the FERC in March 2013. The revised PCA included certain clarifying wording changes that have been agreed upon by intervenors. A decision is pending at the FERC.

In October 2013, the AEP East Companies submitted additional filings with the FERC updating the October 2012 filings to reflect changes necessitated by recent orders from the Virginia State Corporation Commission and the KPSC related to the proposed asset transfers and to position the company for the final stages of corporate separation. See the “Plant Transfers” section of Rate Matters.

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.

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. The Commitments, Guarantees and Contingencies note within KPCo’s 2012 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2013, 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 conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of September 30, 2013, the maximum potential loss for these lease agreements was approximately $1.1 million assuming the fair value of the equipment is zero at the end of the lease term.

CONTINGENCIES

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. In May 2013, the U.S. Court of Appeals for the Fifth Circuit affirmed the district court's dismissal of the complaint. The plaintiffs did not appeal to the U.S. Supreme Court.

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. 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 filed seeking further review in the U.S. Supreme Court. In May 2013, the U.S. Supreme Court denied the plaintiffs' request for review.

5. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans for the three and nine months ended September 30, 2013 and 2012:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	$ 257	$ 353	$ 112	$ 252
Interest Cost	1,234	1,366	458	709
Expected Return on Plan Assets	(1,604)	(1,848)	(737)	(727)
Amortization of Prior Service Cost (Credit)	10	21	(505)	(126)
Amortization of Net Actuarial Loss	1,118	919	421	391
Net Periodic Benefit Cost (Credit)	$ 1,015	$ 811	$ (251)	$ 499

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2013	2012	2013	2012
	(in thousands)			
Service Cost	$ 772	$ 1,059	$ 335	$ 755
Interest Cost	3,704	4,098	1,374	2,127
Expected Return on Plan Assets	(4,814)	(5,544)	(2,212)	(2,183)
Amortization of Prior Service Cost (Credit)	31	63	(1,515)	(378)
Amortization of Net Actuarial Loss	3,353	2,758	1,263	1,175
Net Periodic Benefit Cost (Credit)	$ 3,046	$ 2,434	$ (755)	$ 1,496

6. BUSINESS SEGMENTS

KPCo has one reportable segment, an integrated 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 the KPCo's outstanding derivative contracts as of September 30, 2013 and December 31, 2012:

Notional Volume of Derivative Instruments

	Volume		
	September 30, 2013	**December 31, 2012**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	15,631	18,838	MWhs
Coal	45	247	Tons
Natural Gas	849	2,018	MMBtus
Heating Oil and Gasoline	240	269	Gallons
Interest Rate	$ 3,400	$ 4,836	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 condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2013 and December 31, 2012 condensed balance sheets, KPCo netted $24 thousand and $253 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $1.2 million and $2.2 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 KPCo's derivative activity on the condensed balance sheets as of September 30, 2013 and December 31, 2012:

Fair Value of Derivative Instruments
September 30, 2013

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 14,057	$ 49	$ -	$ 14,106	$ (9,064)	$ 5,042
Long-term Risk Management Assets	6,697	47	-	6,744	(2,450)	4,294
Total Assets	20,754	96	-	20,850	(11,514)	9,336
Current Risk Management Liabilities	12,244	118	-	12,362	(9,979)	2,383
Long-term Risk Management Liabilities	5,152	3	-	5,155	(2,666)	2,489
Total Liabilities	17,396	121	-	17,517	(12,645)	4,872
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,358	$ (25)	$ -	$ 3,333	$ 1,131	$ 4,464

Fair Value of Derivative Instruments
December 31, 2012

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 25,448	$ 72	$ -	$ 25,520	$ (19,345)	$ 6,175
Long-term Risk Management Assets	12,117	43	-	12,160	(5,278)	6,882
Total Assets	37,565	115	-	37,680	(24,623)	13,057
Current Risk Management Liabilities	23,806	239	-	24,045	(20,725)	3,320
Long-term Risk Management Liabilities	9,469	85	-	9,554	(5,854)	3,700
Total Liabilities	33,275	324	-	33,599	(26,579)	7,020
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,290	$ (209)	$ -	$ 4,081	$ 1,956	$ 6,037

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

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

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

The table below presents KPCo's activity of derivative risk management contracts for the three and nine months ended September 30, 2013 and 2012:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Nine Months Ended September 30, 2013 and 2012

Location of Gain (Loss)	Three Months Ended September 30, 2013	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2013	Nine Months Ended September 30, 2012
	(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 714	$ 362	$ 1,160	$ (1,209)
Regulatory Assets (a)	-	(35)	-	(26)
Regulatory Liabilities (a)	(775)	(600)	(944)	1,317
Total Gain (Loss) on Risk Management Contracts	$ (61)	$ (273)	$ 216	$ 82

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. 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 Expense on KPCo's condensed statements of income. During the three and nine months ended September 30, 2013 and 2012, 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 (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2013 and 2012, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three and nine months ended September 30, 2013 and 2012, 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 (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2013 and 2012, 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 (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2013 and 2012, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2013 and 2012, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2013 and 2012, see Note 2.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of September 30, 2013 and December 31, 2012 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2013

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ 64	$ -	$ 64
Hedging Liabilities (a)	89	-	89
AOCI Loss Net of Tax	(7)	(237)	(244)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(35)	(60)	(95)

Impact of Cash Flow Hedges on the Condensed 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)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of September 30, 2013, 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 was 15 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (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 September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 175	$ 432
Amount of Collateral KPCo Would Have Been Required to Post	1,274	741
Amount Attributable to RTO and ISO Activities	1,198	703

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of September 30, 2013 and December 31, 2012:

	September 30, 2013	December 31, 2012
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 5,573	$ 9,907
Amount of Cash Collateral Posted	-	365
Additional Settlement Liability if Cross Default Provision is Triggered	4,567	6,041

8. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

The accounting guidance for "Fair Value Measurements and Disclosures" establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. When quoted market prices are not available, pricing may be completed using comparable securities, dealer values, operating data and general market conditions to determine fair value. Valuation models utilize various inputs such as commodity, interest rate and, to a lesser degree, volatility and credit that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in inactive markets, market corroborated inputs (i.e. inputs derived principally from, or correlated to, observable market data) and other observable inputs for the asset or liability. The 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. If the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Illiquid transactions, complex structured transactions, FTRs and counterparty credit risk may require nonmarket based inputs. Some of these inputs may be internally developed or extrapolated and utilized to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3. The main driver of the contracts being classified as Level 3 is the inability to substantiate energy price curves in the market. A significant portion of the Level 3 instruments have been economically hedged which greatly limits potential earnings volatility.

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo's Long-term Debt as of September 30, 2013 and December 31, 2012 are summarized in the following table:

	September 30, 2013		December 31, 2012	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 549,347	$ 660,951	$ 549,222	$ 708,566

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2013 and December 31, 2012. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 371	$ 17,528	$ 2,823	$ (11,450)	$ 9,272
Cash Flow Hedges:					
Commodity Hedges (a)	-	94	-	(30)	64
Total Risk Management Assets	$ 371	$ 17,622	$ 2,823	$ (11,480)	$ 9,336
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 262	$ 16,527	$ 575	$ (12,581)	$ 4,783
Cash Flow Hedges:					
Commodity Hedges (a)	-	119	-	(30)	89
Total Risk Management Liabilities	$ 262	$ 16,646	$ 575	$ (12,611)	$ 4,872

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2012

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

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

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2013 and 2012.

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

Three Months Ended September 30, 2013	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of June 30, 2013	$ 2,674
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(247)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(218)
Transfers into Level 3 (d) (e)	3
Transfers out of Level 3 (e) (f)	(3)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	39
Balance as of September 30, 2013	$ 2,248

Three Months Ended September 30, 2012	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of June 30, 2012	$ 2,577
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(709)
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	81
Purchases, Issuances and Settlements (c)	186
Transfers into Level 3 (d) (e)	131
Transfers out of Level 3 (e) (f)	(57)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	3
Balance as of September 30, 2012	$ 2,212

Nine Months Ended September 30, 2013	**Net Risk Management Assets (Liabilities)**
	(in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(708)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	354
Transfers into Level 3 (d) (e)	194
Transfers out of Level 3 (e) (f)	(187)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	396
Balance as of September 30, 2013	$ 2,248

Nine Months Ended September 30, 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)	(1,052)
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	63
Purchases, Issuances and Settlements (c)	2,163
Transfers into Level 3 (d) (e)	860
Transfers out of Level 3 (e) (f)	(1,031)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	793
Balance as of September 30, 2012	$ 2,212

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

The following table quantifies the significant unobservable inputs used in developing the fair value of Level 3 positions as of September 30, 2013:

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 2,371	$ 400	Discounted Cash Flow	Forward Market Price	$ 12.52	$ 55.40
FTRs	452	175	Discounted Cash Flow	Forward Market Price	(5.26)	10.85
Total	$ 2,823	$ 575				

(a) Represents market prices in dollars per MWh.

9. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. The completion of the federal audit did not result in a material impact on net income, cash flows or financial condition. 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. KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2008.

Federal Tax Regulations

In the third quarter of 2013, the U.S. Treasury Department issued final regulations regarding the deduction and capitalization of expenditures related to tangible property, effective for the tax years beginning in 2014. The U.S. Treasury Department had previously issued guidance in the form of proposed and temporary regulations which was generally effective for tax years beginning in 2012, which was moved to tax years beginning in 2014 in November, 2012. In addition, the IRS has issued Revenue Procedures under the Industry Issue Resolutions program that provides specific guidance for the implementation of the regulations for the electric utility industry. The impact of these final regulations is not material to net income, cash flows or financial condition.

State Tax Legislation

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

10. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first nine months of 2013.

In July 2013, AEPGenCo, APCo, KPCo and OPCo entered into a $1 billion term credit facility due in May 2015 to provide liquidity during the corporate separation process. Under the credit facility, OPCo may assign borrowings to AEPGenCo upon the transfer of OPCo's generation assets to AEPGenCo. Subject to regulatory approval, AEPGenCo may further assign a portion of the borrowings to APCo and KPCo, not to exceed $500 million and $250 million, respectively, upon AEPGenCo's subsequent transfer of certain of those generation assets to APCo and KPCo.

Dividend Restrictions

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

Federal Power Act

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

Leverage Restrictions

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

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of September 30, 2013 and December 31, 2012 are included in Advances to Affiliates and Advances from Affiliates, respectively, on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the nine months ended September 30, 2013 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Loans to the Utility Money Pool as of September 30, 2013	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 32,649	$ 31,421	$ 11,271	$ 16,214	$ 6,300	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the nine months ended September 30, 2013 and 2012 are summarized in the following table:

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2013	0.43 %	0.35 %	0.36 %	0.28 %	0.38 %	0.32 %
2012	- %	- %	0.56 %	0.44 %	- %	0.48 %

Sale of Receivables – AEP Credit

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

In June 2013, AEP Credit amended its receivables securitization agreement. The agreement provides a commitment of $700 million from bank conduits to purchase receivables. AEP Credit amended a commitment of $385 million to now expire in June 2014. 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 $39 million and $46 million as of September 30, 2013 and December 31, 2012, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended September 30, 2013 and 2012 were $493 thousand and $605 thousand, respectively, and for the nine months ended September 30, 2013 and 2012 were $1.5 million and $1.9 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended September 30, 2013 and 2012 were $130 million and $122 million, respectively, and for the nine months ended September 30, 2013 and 2012 were $398 million and $387 million, respectively.

11. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended September 30, 2013 and 2012 were both $8 million and for the nine months ended September 30, 2013 and 2012 were both $23 million. The carrying amount of liabilities associated with AEPSC as of September 30, 2013 and December 31, 2012 was $2 million and $6 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended September 30, 2013 and 2012 were both $28 million and for the nine months ended September 30, 2013 and 2012 were both $76 million. The carrying amount of liabilities associated with AEGCo as of September 30, 2013 and December 31, 2012 was $9 million and $10 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

12. 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 facilitate an organizational and process evaluation and a second firm to evaluate current employee benefit programs. The process resulted in involuntary severances and was 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 of $1.7 million to Other Operation expense in 2012 primarily related to severance benefits as a result of the sustainable cost reductions initiative. In addition, the sustainable cost reduction activity for the nine months ended September 30, 2013 is described in the following table:

Balance as of December 31, 2012	Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance as of September 30, 2013
		(in thousands)			
$ 497	$ 167	$ -	$ (263)	$ (400)	$ 1

These expenses, net of adjustments, relate primarily to severance benefits and are included primarily in Other Operation expense on the condensed statements of income. Management does not expect additional costs to be incurred related to this initiative.

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GLOSSARY OF TERMS

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
REVENUES		
Electric Generation, Transmission and Distribution	$ 227,631	$ 201,315
Sales to AEP Affiliates	5,415	29,197
Other Revenues	84	132
TOTAL REVENUES	233,130	230,644
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	72,362	74,680
Purchased Electricity for Resale	3,113	3,370
Purchased Electricity from AEP Affiliates	31,422	56,490
Other Operation	19,865	18,333
Maintenance	18,642	17,083
Depreciation and Amortization	23,522	23,109
Taxes Other Than Income Taxes	5,303	4,972
TOTAL EXPENSES	174,229	198,037
OPERATING INCOME	58,901	32,607
Other Income (Expense):		
Interest Income	33	27
Allowance for Equity Funds Used During Construction	1,456	261
Interest Expense	(9,101)	(11,572)
INCOME BEFORE INCOME TAX EXPENSE	51,289	21,323
Income Tax Expense	18,741	6,920
NET INCOME	$ 32,548	$ 14,403

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	Three Months Ended March 31, 2013
Net Income	$ 32,548	$ 14,403
OTHER COMPREHENSIVE INCOME, NET OF TAXES		
Cash Flow Hedges, Net of Tax of $5 and $118 in 2014 and 2013, Respectively	10	218
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $63 and $134 in 2014 and 2013, Respectively	117	248
TOTAL OTHER COMPREHENSIVE INCOME	127	466
TOTAL COMPREHENSIVE INCOME	$ 32,675	$ 14,869

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 50,450	$ 531,536	$ 190,819	$ (19,994)	$ 752,811
Capital Contribution from Parent		231			231
Common Stock Dividends			(3,892)		(3,892)
Net Income			14,403		14,403
Other Comprehensive Income				466	466
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2013	$ 50,450	$ 531,767	$ 201,330	$ (19,528)	$ 764,019
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(15,000)		(15,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			32,548		32,548
Other Comprehensive Income				127	127
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY – MARCH 31, 2014	$ 50,450	$ 517,460	$ 197,239	$ (6,601)	$ 758,548

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	March 31, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 1,244	$ 743
Accounts Receivable:		
Customers	11,974	17,889
Affiliated Companies	28,281	9,781
Accrued Unbilled Revenues	12	857
Miscellaneous	106	75
Allowance for Uncollectible Accounts	(63)	(78)
Total Accounts Receivable	40,310	28,524
Fuel	45,433	92,313
Materials and Supplies	41,141	43,940
Risk Management Assets	4,277	4,356
Accrued Tax Benefits	35	5,249
Regulatory Asset for Under-Recovered Fuel Costs	10,594	-
Prepayments and Other Current Assets	5,595	3,284
TOTAL CURRENT ASSETS	148,629	178,409
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,063,586	1,052,757
Transmission	510,963	507,844
Distribution	698,685	693,481
Other Property, Plant and Equipment (Including Plant to be Retired)	477,716	480,759
Construction Work in Progress	139,321	128,599
Total Property, Plant and Equipment	2,890,271	2,863,440
Accumulated Depreciation and Amortization	962,785	943,889
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,927,486	1,919,551
OTHER NONCURRENT ASSETS		
Regulatory Assets	214,765	216,360
Long-term Risk Management Assets	2,880	3,484
Employee Benefits and Pension Assets	13,804	11,446
Deferred Charges and Other Noncurrent Assets	14,618	20,207
TOTAL OTHER NONCURRENT ASSETS	246,067	251,497
TOTAL ASSETS	$ 2,322,182	$ 2,349,457

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
March 31, 2014 and December 31, 2013
(Unaudited)

	March 31, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 49,404	$ 8,564
Accounts Payable:		
General	42,993	21,619
Affiliated Companies	25,648	39,171
Risk Management Liabilities	905	1,828
Customer Deposits	25,289	25,211
Deferred Income Taxes	10,055	6,486
Accrued Taxes	26,216	20,801
Accrued Interest	5,640	6,678
Regulatory Liability for Over-Recovered Fuel Costs	-	2,851
Other Current Liabilities	20,681	19,411
TOTAL CURRENT LIABILITIES	206,831	152,620
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	729,430	729,389
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	1,630	2,105
Deferred Income Taxes	546,344	549,672
Regulatory Liabilities and Deferred Investment Tax Credits	24,490	22,926
Employee Benefits and Pension Obligations	7,754	6,041
Deferred Credits and Other Noncurrent Liabilities	27,155	27,335
TOTAL NONCURRENT LIABILITIES	1,356,803	1,357,468
TOTAL LIABILITIES	1,563,634	1,510,088
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	517,460	614,648
Retained Earnings	197,239	179,691
Accumulated Other Comprehensive Income (Loss)	(6,601)	(5,420)
TOTAL COMMON SHAREHOLDER'S EQUITY	758,548	839,369
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,322,182	$ 2,349,457

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended March 31, 2014	2013
OPERATING ACTIVITIES		
Net Income	$ 32,548	$ 14,403
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	23,522	23,109
Deferred Income Taxes	2,118	7,924
Allowance for Equity Funds Used During Construction	(1,456)	(261)
Mark-to-Market of Risk Management Contracts	(707)	1,798
Property Taxes	3,784	3,603
Fuel Over/Under-Recovery, Net	(13,445)	(7,945)
Change in Other Noncurrent Assets	626	373
Change in Other Noncurrent Liabilities	717	1,017
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(11,786)	15,743
Fuel, Materials and Supplies	49,679	25,257
Accounts Payable	(505)	(35,052)
Accrued Taxes, Net	10,629	(76)
Accrued Interest	(1,038)	(5,229)
Other Current Assets	(1,530)	904
Other Current Liabilities	1,481	(6,083)
Net Cash Flows from Operating Activities	94,637	39,485
INVESTING ACTIVITIES		
Construction Expenditures	(20,979)	(35,241)
Acquisitions of Assets	(1,036)	(18)
Proceeds from Sales of Assets	85	1,255
Other Investing Activities	98	-
Net Cash Flows Used for Investing Activities	(21,832)	(34,004)
FINANCING ACTIVITIES		
Capital Contribution from (Returned to) Parent	(100,000)	231
Change in Advances from Affiliates, Net	40,840	(2,320)
Principal Payments for Capital Lease Obligations	(1,208)	(317)
Dividends Paid on Common Stock	(15,000)	(3,892)
Other Financing Activities	3,064	197
Net Cash Flows Used for Financing Activities	(72,304)	(6,101)
Net Increase (Decrease) in Cash and Cash Equivalents	501	(620)
Cash and Cash Equivalents at Beginning of Period	743	1,482
Cash and Cash Equivalents at End of Period	$ 1,244	$ 862
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 9,888	$ 16,596
Net Cash Paid for Income Taxes	-	111
Noncash Acquisitions Under Capital Leases	596	721
Construction Expenditures Included in Current Liabilities as of March 31,	15,540	19,185

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

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three months ended March 31, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed financial statements are unaudited and should be read in conjunction with the audited 2013 financial statements and notes thereto, which are included in KPCo's 2013 Annual Report.

Management reviewed subsequent events through April 25, 2014, the date that the first quarter 2014 report was issued.

Revenue Recognition

Electricity Supply and Delivery Activities – Transactions with PJM

Revenues are recognized 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 include unbilled as well as billed amounts.

KPCo sells power produced at its generation plants to PJM and purchase power from PJM to supply its retail load. These power sales and purchases for retail load are netted hourly for financial reporting purposes. On an hourly net basis, KPCo records sales of power to PJM in excess of purchases of power as revenues. Also, on an hourly net basis, KPCo records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale. Upon termination of the Interconnection Agreement, KPCo manages and accounts for its purchases and sales with PJM individually based on market prices.

2. NEW ACCOUNTING PRONOUNCEMENT

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

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

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

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management plans to adopt ASU 2014-08 effective January 1, 2015.

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three months ended March 31, 2014 and 2013. All amounts in the following tables are presented net of related income taxes.

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

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

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended March 31, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (19,585)	$ (19,994)
Change in Fair Value Recognized in AOCI	161	-	-	161
Amounts Reclassified from AOCI	42	15	248	305
Net Current Period Other Comprehensive Income	203	15	248	466
Balance in AOCI as of March 31, 2013	$ 76	$ (267)	$ (19,337)	$ (19,528)

Reclassifications Out of Accumulated Other Comprehensive Income

The following table provides details of reclassifications from AOCI for the three months ended March 31, 2014 and 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended March 31, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended March 31,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$ -	$ 19
Purchased Electricity for Resale	(452)	54
Other Operation Expense	(3)	(3)
Maintenance Expense	(5)	(2)
Property, Plant and Equipment	(6)	(4)
Regulatory Assets/(Liabilities), Net (a)	(43)	-
Subtotal - Commodity	(509)	64
Interest Rate and Foreign Currency:		
Interest Expense	23	23
Subtotal - Interest Rate and Foreign Currency	23	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	(486)	87
Income Tax (Expense) Credit	(170)	30
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(316)	57
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(54)	(91)
Amortization of Actuarial (Gains)/Losses	234	472
Reclassifications from AOCI, before Income Tax (Expense) Credit	180	381
Income Tax (Expense) Credit	63	133
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	117	248
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (199)	$ 305

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

4. RATE MATTERS

As discussed in KPCo's 2013 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2013 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2014 and updates KPCo's 2013 Annual Report.

Regulatory Assets Not Yet Being Recovered

	March 31, 2014	December 31, 2013
Noncurrent Regulatory Assets	(in thousands)	
Regulatory assets not yet being recovered pending future proceedings:		
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 12,146	$ 12,146
Total Regulatory Assets Not Yet Being Recovered	$ 12,146	$ 12,146

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

Plant Transfer

In October 2012, the AEP East Companies submitted several filings with the FERC. 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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of March 31, 2014, the net book value of Big Sandy Plant, Unit 2 was $247 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo’s request to defer FGD project costs for Big Sandy Plant, Unit 2. As a result of this order, in 2013, KPCo recorded a pretax regulatory disallowance of $33 million in Asset Impairments and Other Related Charges on the statement of income. In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In December 2013, KPCo filed motions with the Franklin County Circuit Court to dismiss the appeal. A hearing on the motions to dismiss was held in January 2014. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed. If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo’s business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo’s 2013 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of March 31, 2014, 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 conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of March 31, 2014, the maximum potential loss for these lease agreements was approximately $1.2 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following table provides the components of KPCo's net periodic benefit cost (credit) for the plans for the three months ended March 31, 2014 and 2013:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$ 575	$ 470	$ 118	$ 208
Interest Cost	2,010	1,827	601	643
Expected Return on Plan Assets	(2,418)	(2,564)	(1,060)	(1,030)
Amortization of Prior Service Cost (Credit)	14	14	(606)	(611)
Amortization of Net Actuarial Loss	1,117	1,651	187	588
Net Periodic Benefit Cost (Credit)	$ 1,298	$ 1,398	$ (760)	$ (202)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, 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 extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo's commodity portfolio. For disclosure purposes, such risks are grouped as "Commodity," as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt 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 the KPCo's outstanding derivative contracts as of March 31, 2014 and December 31, 2013:

Notional Volume of Derivative Instruments

	Volume		
	March 31, 2014	**December 31, 2013**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	5,900	10,071	MWhs
Coal	447	2	Tons
Natural Gas	398	509	MMBtus
Heating Oil and Gasoline	190	261	Gallons
Interest Rate	$ 2,236	$ 2,615	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 and natural gas ("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. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. For disclosure purposes, these contracts were included with other hedging activities as "Commodity" as of December 31, 2013. As of March 31, 2014, these contracts will be grouped as "Commodity" with other risk management activities. KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. 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 condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2014 and December 31, 2013 condensed balance sheets, KPCo netted $7 thousand and $0 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $280 thousand and $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 KPCo's derivative activity on the condensed balance sheets as of March 31, 2014 and December 31, 2013:

Fair Value of Derivative Instruments
March 31, 2014

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 8,291	$ 46	$ -	$ 8,337	$ (4,060)	$ 4,277
Long-term Risk Management Assets	3,557	-	-	3,557	(677)	2,880
Total Assets	11,848	46	-	11,894	(4,737)	7,157
Current Risk Management Liabilities	5,151	18	-	5,169	(4,264)	905
Long-term Risk Management Liabilities	2,376	-	-	2,376	(746)	1,630
Total Liabilities	7,527	18	-	7,545	(5,010)	2,535
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,321	$ 28	$ -	$ 4,349	$ 273	$ 4,622

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 9,520	$ 85	$ -	$ 9,605	$ (5,249)	$ 4,356
Long-term Risk Management Assets	4,306	-	-	4,306	(822)	3,484
Total Assets	13,826	85	-	13,911	(6,071)	7,840
Current Risk Management Liabilities	7,583	65	-	7,648	(5,820)	1,828
Long-term Risk Management Liabilities	2,970	-	-	2,970	(865)	2,105
Total Liabilities	10,553	65	-	10,618	(6,685)	3,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,273	$ 20	$ -	$ 3,293	$ 614	$ 3,907

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

The table below presents KPCo's activity of derivative risk management contracts for the three months ended March 31, 2014 and 2013:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2014 and 2013

Location of Gain (Loss)	2014	2013
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 6,940	$ 596
Fuel and Other Consumables Used for Electric Generation	1	-
Regulatory Assets (a)	-	-
Regulatory Liabilities (a)	1,120	(467)
Total Gain on Risk Management Contracts	$ 8,061	$ 129

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. 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 Expense on KPCo's condensed statements of income. During the three months ended March 31, 2014 and 2013, 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 (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three months ended March 31, 2014 and 2013, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three months ended March 31, 2013, KPCo designated heating oil and gasoline derivatives as cash flow hedges. KPCo discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three months ended March 31, 2014 and 2013, 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 (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three months ended March 31, 2014 and 2013, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During the three months ended March 31, 2014 and 2013, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three months ended March 31, 2014 and 2013, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of March 31, 2014 and December 31, 2013 were:

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

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 43	$ -	$ 43
Hedging Liabilities (a)	15	-	15
AOCI Gain (Loss) Net of Tax	17	(206)	(189)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	17	(60)	(43)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 79	$ -	$ 79
Hedging Liabilities (a)	59	-	59
AOCI Gain (Loss) Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of March 31, 2014, 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 was 2 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (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 March 31, 2014 and December 31, 2013:

	March 31, 2014	December 31, 2013
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 57	$ 118
Amount of Collateral KPCo Would Have Been Required to Post	1,079	565
Amount Attributable to RTO and ISO Activities	981	522

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of March 31, 2014 and December 31, 2013:

	March 31, 2014	December 31, 2013
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 3,366	$ 4,039
Amount of Cash Collateral Posted	-	-
Additional Settlement Liability if Cross Default Provision is Triggered	2,644	3,817

9. <u>FAIR VALUE MEASUREMENTS</u>

Fair Value Hierarchy and Valuation Techniques

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

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

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo's Long-term Debt as of March 31, 2014 and December 31, 2013 are summarized in the following table:

	March 31, 2014		December 31, 2013	
	Book Value	**Fair Value**	**Book Value**	**Fair Value**
	(in thousands)			
Long-term Debt	$ 749,430	$ 860,557	$ 749,389	$ 841,594

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2014 and December 31, 2013. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 81	$ 9,058	$ 2,087	$ (4,112)	$ 7,114
Cash Flow Hedges:					
Commodity Hedges (a)	-	46	-	(3)	43
Total Risk Management Assets	$ 81	$ 9,104	$ 2,087	$ (4,115)	$ 7,157
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 63	$ 6,205	$ 637	$ (4,385)	$ 2,520
Cash Flow Hedges:					
Commodity Hedges (a)	-	18	-	(3)	15
Total Risk Management Liabilities	$ 63	$ 6,223	$ 637	$ (4,388)	$ 2,535

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Cash Flow Hedges:					
Commodity Hedges (a)	-	85	-	(6)	79
Total Risk Management Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Cash Flow Hedges:					
Commodity Hedges (a)	-	65	-	(6)	59
Total Risk Management Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

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

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2014 and 2013.

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

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

Three Months Ended March 31, 2013	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(297)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	55
Transfers into Level 3 (d) (e)	126
Transfers out of Level 3 (e) (f)	(107)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	(172)
Balance as of March 31, 2013	$ 1,804

(a) Included in revenues on KPCo's condensed statements of income.

(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.

(c) Represents the settlement of risk management commodity contracts for the reporting period.

(d) Represents existing assets or liabilities that were previously categorized as Level 2.

(e) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

(f) Represents existing assets or liabilities that were previously categorized as Level 3.

(g) Relates to the net gains (losses) of those contracts that are not reflected on KPCo's condensed statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of March 31, 2014 and December 31, 2013:

Significant Unobservable Inputs
March 31, 2014

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	**Liabilities**	**Technique**	**Unobservable Input (a)**	**Low**	**High**
	(in thousands)					
Energy Contracts	$ 1,327	$ 580	Discounted Cash Flow	Forward Market Price	$ 13.34	$ 59.60
FTRs	760	57	Discounted Cash Flow	Forward Market Price	(5.05)	9.17
Total	$ 2,087	$ 637				

Significant Unobservable Inputs
December 31, 2013

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	**Liabilities**	**Technique**	**Unobservable Input (a)**	**Low**	**High**
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

(a) Represents market prices in dollars per MWh.

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. The IRS examination of years 2011 and 2012 started in April 2014. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

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

11. FINANCING ACTIVITIES

Long-term Debt

KPCo did not have any long-term debt issuances or retirements during the first three months of 2014.

Dividend Restrictions

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

Federal Power Act

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

Leverage Restrictions

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

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding borrowings from the Utility Money Pool as of March 31, 2014 and December 31, 2013 are included in Advances from Affiliates on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2014 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Borrowings from the Utility Money Pool as of March 31, 2014	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 50,366	$ 50,332	$ 20,343	$ 34,026	$ 49,404	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the three months ended March 31, 2014 and 2013 are summarized in the following table:

Three Months Ended March 31,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2014	0.33 %	0.28 %	0.33 %	0.28 %	0.31 %	0.32 %
2013	0.43 %	0.35 %	0.36 %	0.36 %	0.38 %	0.36 %

Sale of Receivables – AEP Credit

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

AEP Credit's receivables securitization agreement provides a commitment of $700 million from bank conduits to purchase receivables. A commitment of $385 million expires in June 2014. The remaining commitment of $315 million expires in June 2015. AEP Credit intends to extend or replace the agreement expiring in June 2014 on or before its maturity.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $60 million and $43 million as of March 31, 2014 and December 31, 2013, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended March 31, 2014 and 2013 were $763 thousand and $520 thousand, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended March 31, 2014 and 2013 were $179 million and $140 million, respectively.

12. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended March 31, 2014 and 2013 were $13 million and $7 million, respectively. The carrying amount of liabilities associated with AEPSC as of March 31, 2014 and December 31, 2013 was $5 million and $4 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended March 31, 2014 and 2013 were $30 million and $25 million, respectively. The carrying amount of liabilities associated with AEGCo as of March 31, 2014 and December 31, 2013 was $11 million and $11 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

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GLOSSARY OF TERMS

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
REVENUES				
Electric Generation, Transmission and Distribution	$ 205,104	$ 159,960	$ 432,735	$ 361,275
Sales to AEP Affiliates	1,275	21,439	6,690	50,636
Other Revenues	184	150	268	282
TOTAL REVENUES	206,563	181,549	439,693	412,193
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	79,606	37,802	151,968	112,482
Purchased Electricity for Resale	2,057	2,940	5,170	6,310
Purchased Electricity from AEP Affiliates	27,938	59,418	59,360	115,908
Other Operation	18,940	16,962	38,805	35,295
Maintenance	17,724	18,451	36,366	35,534
Depreciation and Amortization	23,033	22,662	46,555	45,771
Taxes Other Than Income Taxes	5,287	5,100	10,590	10,072
TOTAL EXPENSES	174,585	163,335	348,814	361,372
OPERATING INCOME	31,978	18,214	90,879	50,821
Other Income (Expense):				
Interest Income	47	217	80	244
Allowance for Equity Funds Used During Construction	1,260	404	2,716	665
Interest Expense	(9,241)	(11,506)	(18,342)	(23,078)
INCOME BEFORE INCOME TAX EXPENSE	24,044	7,329	75,333	28,652
Income Tax Expense	8,786	2,344	27,527	9,264
NET INCOME	$ 15,258	$ 4,985	$ 47,806	$ 19,388

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Six Months Ended June 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	**2013**	**2014**	**2013**
Net Income	$ 15,258	$ 4,985	$ 47,806	$ 19,388
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $1 and $12 for the Three Months Ended June 30, 2014 and 2013, Respectively, and $4 and $106 for the Six Months Ended June 30, 2014 and 2013, Respectively	(2)	(22)	8	196
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $62 and $149 for the Three Months Ended June 30, 2014 and 2013, Respectively, and $125 and $283 for the Six Months Ended June 30, 2014 and 2013, Respectively	116	277	233	525
TOTAL OTHER COMPREHENSIVE INCOME	114	255	241	721
TOTAL COMPREHENSIVE INCOME	$ 15,372	$ 5,240	$ 48,047	$ 20,109

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Six Months Ended June 30, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2012	$ 50,450	$ 531,536	$ 190,819	$ (19,994)	$ 752,811
Capital Contribution from Parent		11,458			11,458
Common Stock Dividends			(8,514)		(8,514)
Net Income			19,388		19,388
Other Comprehensive Income				721	721
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2013	$ 50,450	$ 542,994	$ 201,693	$ (19,273)	$ 775,864
TOTAL COMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(30,000)		(30,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			47,806		47,806
Other Comprehensive Income				241	241
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY – JUNE 30, 2014	$ 50,450	$ 517,460	$ 197,497	$ (6,487)	$ 758,920

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	June 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 828	$ 743
Advances to Affiliates	49,348	-
Accounts Receivable:		
Customers	20,290	17,889
Affiliated Companies	28,402	9,781
Accrued Unbilled Revenues	10	857
Miscellaneous	131	75
Allowance for Uncollectible Accounts	(29)	(78)
Total Accounts Receivable	48,804	28,524
Fuel	24,900	92,313
Materials and Supplies	38,541	43,940
Risk Management Assets	5,389	4,356
Accrued Tax Benefits	35	5,249
Regulatory Asset for Under-Recovered Fuel Costs	10,175	-
Prepayments and Other Current Assets	3,467	3,284
TOTAL CURRENT ASSETS	181,487	178,409
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,137,930	1,052,757
Transmission	512,624	507,844
Distribution	706,036	693,481
Other Property, Plant and Equipment (Including Plant to be Retired)	511,154	480,759
Construction Work in Progress	93,023	128,599
Total Property, Plant and Equipment	2,960,767	2,863,440
Accumulated Depreciation and Amortization	982,243	943,889
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,978,524	1,919,551
OTHER NONCURRENT ASSETS		
Regulatory Assets	213,989	216,360
Long-term Risk Management Assets	1,639	3,484
Employee Benefits and Pension Assets	15,901	11,446
Deferred Charges and Other Noncurrent Assets	10,918	20,207
TOTAL OTHER NONCURRENT ASSETS	242,447	251,497
TOTAL ASSETS	$ 2,402,458	$ 2,349,457

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
June 30, 2014 and December 31, 2013
(Unaudited)

	June 30, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 8,564
Accounts Payable:		
General	56,509	21,619
Affiliated Companies	26,676	39,171
Long-term Debt Due Within One Year – Nonaffiliated	265,000	-
Long-term Debt Due Within One Year – Affiliated	20,000	-
Risk Management Liabilities	884	1,828
Customer Deposits	24,986	25,211
Deferred Income Taxes	9,350	6,486
Accrued Taxes	32,458	20,801
Accrued Interest	6,627	6,678
Regulatory Liability for Over-Recovered Fuel Costs	-	2,851
Other Current Liabilities	22,652	19,411
TOTAL CURRENT LIABILITIES	465,142	152,620
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	529,472	729,389
Long-term Debt – Affiliated	-	20,000
Long-term Risk Management Liabilities	774	2,105
Deferred Income Taxes	544,514	549,672
Regulatory Liabilities and Deferred Investment Tax Credits	24,044	22,926
Employee Benefits and Pension Obligations	7,681	6,041
Deferred Credits and Other Noncurrent Liabilities	71,911	27,335
TOTAL NONCURRENT LIABILITIES	1,178,396	1,357,468
TOTAL LIABILITIES	1,643,538	1,510,088
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	517,460	614,648
Retained Earnings	197,497	179,691
Accumulated Other Comprehensive Income (Loss)	(6,487)	(5,420)
TOTAL COMMON SHAREHOLDER'S EQUITY	758,920	839,369
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,402,458	$ 2,349,457

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2014 and 2013
(in thousands)
(Unaudited)

	Six Months Ended June 30, 2014	Six Months Ended June 30, 2013
OPERATING ACTIVITIES		
Net Income	$ 47,806	$ 19,388
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	46,555	45,771
Deferred Income Taxes	(1,571)	8,236
Allowance for Equity Funds Used During Construction	(2,716)	(665)
Mark-to-Market of Risk Management Contracts	(1,482)	1,208
Pension Contributions to Qualified Plan Trust	(1,923)	-
Property Taxes	7,076	6,794
Fuel Over/Under-Recovery, Net	(13,026)	(6,355)
Change in Other Noncurrent Assets	1,203	(1,219)
Change in Other Noncurrent Liabilities	2,592	3,063
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(20,280)	22,962
Fuel, Materials and Supplies	72,812	20,034
Accounts Payable	9,211	(35,956)
Accrued Taxes, Net	17,089	(4,167)
Accrued Interest	(50)	(592)
Other Current Assets	(426)	2,691
Other Current Liabilities	3,180	(6,479)
Net Cash Flows from Operating Activities	166,050	74,714
INVESTING ACTIVITIES		
Construction Expenditures	(44,812)	(65,091)
Change in Advances to Affiliates, Net	(49,348)	(4,600)
Acquisitions of Assets	(1,030)	(55)
Proceeds from Sales of Assets	166	5,448
Other Investing Activities	248	-
Net Cash Flows Used for Investing Activities	(94,776)	(64,298)
FINANCING ACTIVITIES		
Capital Contribution from (Returned to) Parent	(100,000)	11,458
Issuance of Long-term Debt – Nonaffiliated	64,780	-
Change in Advances from Affiliates, Net	(8,564)	(13,359)
Principal Payments for Capital Lease Obligations	(1,489)	(671)
Dividends Paid on Common Stock	(30,000)	(8,514)
Other Financing Activities	4,084	234
Net Cash Flows Used for Financing Activities	(71,189)	(10,852)
Net Increase (Decrease) in Cash and Cash Equivalents	85	(436)
Cash and Cash Equivalents at Beginning of Period	743	1,482
Cash and Cash Equivalents at End of Period	$ 828	$ 1,046
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 17,891	$ 23,083
Net Cash Paid for Income Taxes	5,788	5,969
Noncash Acquisitions Under Capital Leases	1,252	848
Construction Expenditures Included in Current Liabilities as of June 30,	20,184	20,698

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

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed financial statements are unaudited and should be read in conjunction with the audited 2013 financial statements and notes thereto, which are included in KPCo's 2013 Annual Report.

Management reviewed subsequent events through July 25, 2014, the date that the second quarter 2014 report was issued.

Revenue Recognition

Electricity Supply and Delivery Activities – Transactions with PJM

Revenues are recognized 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.

KPCo sells power produced at its generation plants to PJM and purchases power from PJM to supply its retail load. These power sales and purchases for retail load are netted hourly for financial reporting purposes. On an hourly net basis, KPCo records sales of power to PJM in excess of purchases of power from PJM as revenues on the statements of income. Also, on an hourly net basis, KPCo records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale on the statements of income. Upon termination of the Interconnection Agreement in 2014, KPCo manages and accounts for its purchases and sales with PJM individually based on market prices.

Asset Retirement Obligations (ARO)

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

The following is a reconciliation of the June 30, 2014 aggregate carrying amount of ARO for KPCo:

ARO as of December 31, 2013	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of June 30, 2014
		(in thousands)			
$ 20,526	$ 652	$ 42,578	$ (385)	$ -	$ 63,371

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share. Management plans to adopt ASU 2014-08 effective January 1, 2015.

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

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

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

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and six months ended June 30, 2014 and 2013. All amounts in the following tables are presented net of related income taxes.

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

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

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended June 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of March 31, 2013	$ 76	$ (267)	$ -	$ (191)
Change in Fair Value Recognized in AOCI	(22)	-	-	(22)
Amounts Reclassified from AOCI	(15)	15	-	-
Net Current Period Other Comprehensive Income	(37)	15	-	(22)
Balance in AOCI as of June 30, 2013	$ 39	$ (252)	$ -	$ (213)

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

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

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Six Months Ended June 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
		(in thousands)		
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ -	$ (409)
Change in Fair Value Recognized in AOCI	139	-	-	139
Amounts Reclassified from AOCI	27	30	-	57
Net Current Period Other Comprehensive Income	166	30	-	196
Balance in AOCI as of June 30, 2013	$ 39	$ (252)	$ -	$ (213)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and six months ended June 30, 2014 and 2013.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended June 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended June 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$ -	$ 12
Purchased Electricity for Resale	(60)	(30)
Other Operation Expense	-	(2)
Property, Plant and Equipment	-	(2)
Subtotal - Commodity	(60)	(22)
Interest Rate and Foreign Currency:		
Interest Expense	23	23
Subtotal - Interest Rate and Foreign Currency	23	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	(37)	1
Income Tax (Expense) Credit	(13)	1
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(24)	-
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(53)	-
Amortization of Actuarial (Gains)/Losses	232	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	179	-
Income Tax (Expense) Credit	63	-
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	116	-
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 92	$ -

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Six Months Ended June 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI	
	Six Months Ended June 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$ -	$ 31
Purchased Electricity for Resale	(512)	24
Other Operation Expense	(3)	(5)
Maintenance Expense	(5)	(2)
Property, Plant and Equipment	(6)	(6)
Regulatory Assets/(Liabilities), Net (a)	(43)	-
Subtotal - Commodity	(569)	42
Interest Rate and Foreign Currency:		
Interest Expense	46	46
Subtotal - Interest Rate and Foreign Currency	46	46
Reclassifications from AOCI, before Income Tax (Expense) Credit	(523)	88
Income Tax (Expense) Credit	(183)	31
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(340)	57
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(107)	-
Amortization of Actuarial (Gains)/Losses	466	-
Reclassifications from AOCI, before Income Tax (Expense) Credit	359	-
Income Tax (Expense) Credit	126	-
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	233	-
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ (107)	$ 57

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

4. RATE MATTERS

As discussed in KPCo’s 2013 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo’s 2013 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2014 and updates KPCo’s 2013 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	June 30, 2014	December 31, 2013
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 12,146	$ 12,146
Total Regulatory Assets Pending Final Regulatory Approval	$ 12,146	$ 12,146

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

Plant Transfer

In 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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of June 30, 2014, the net book value of Big Sandy Plant, Unit 2 was $276 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo’s request to defer FGD project costs for Big Sandy Plant, Unit 2. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In May 2014, KPCo's motion to dismiss the appeal was denied. In May 2014, KPCo filed motions for reconsideration and clarification with the Franklin County Circuit Court. In June 2014, the motion for reconsideration was denied but the motion to clarify was granted, thereby limiting the appeal to the issues of law presented in the Attorney General's appeal. If any part of the KPSC order is overturned, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2013 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of June 30, 2014, 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 conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of June 30, 2014, the maximum potential loss for these lease agreements was approximately $1.1 million assuming the fair value of the equipment is zero at the end of the lease term.

6. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans for the three and six months ended June 30, 2014 and 2013:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$ 575	$ 470	$ 118	$ 208
Interest Cost	2,011	1,826	601	642
Expected Return on Plan Assets	(2,419)	(2,563)	(1,059)	(1,031)
Amortization of Prior Service Cost (Credit)	14	15	(606)	(610)
Amortization of Net Actuarial Loss	1,116	1,650	186	588
Net Periodic Benefit Cost (Credit)	$ 1,297	$ 1,398	$ (760)	$ (203)

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$ 1,150	$ 940	$ 236	$ 416
Interest Cost	4,021	3,653	1,202	1,285
Expected Return on Plan Assets	(4,837)	(5,127)	(2,119)	(2,061)
Amortization of Prior Service Cost (Credit)	28	29	(1,212)	(1,221)
Amortization of Net Actuarial Loss	2,233	3,301	373	1,176
Net Periodic Benefit Cost (Credit)	$ 2,595	$ 2,796	$ (1,520)	$ (405)

7. BUSINESS SEGMENTS

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

8. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, 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 extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo’s commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt 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 the KPCo’s outstanding derivative contracts as of June 30, 2014 and December 31, 2013:

Notional Volume of Derivative Instruments

	Volume		
	June 30, 2014	**December 31, 2013**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	13,264	10,071	MWhs
Coal	246	2	Tons
Natural Gas	326	509	MMBtus
Heating Oil and Gasoline	213	261	Gallons
Interest Rate	$ 1,653	$ 2,615	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 and natural gas ("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. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. For disclosure purposes, these contracts were included with other hedging activities as "Commodity" as of December 31, 2013. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. 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 condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2014 and December 31, 2013 condensed balance sheets, KPCo netted \$282 thousand and \$0 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and \$164 thousand and \$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 KPCo's derivative activity on the condensed balance sheets as of June 30, 2014 and December 31, 2013:

Fair Value of Derivative Instruments
June 30, 2014

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 8,420	$ -	$ -	$ 8,420	$ (3,031)	$ 5,389
Long-term Risk Management Assets	2,090	-	-	2,090	(451)	1,639
Total Assets	10,510	-	-	10,510	(3,482)	7,028
Current Risk Management Liabilities	3,878	-	-	3,878	(2,994)	884
Long-term Risk Management Liabilities	1,144	-	-	1,144	(370)	774
Total Liabilities	5,022	-	-	5,022	(3,364)	1,658
Total MTM Derivative Contract Net Assets (Liabilities)	$ 5,488	$ -	$ -	$ 5,488	$ (118)	$ 5,370

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts: Commodity (a)	Hedging Contracts: Commodity (a)	Hedging Contracts: Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 9,520	$ 85	$ -	$ 9,605	$ (5,249)	$ 4,356
Long-term Risk Management Assets	4,306	-	-	4,306	(822)	3,484
Total Assets	13,826	85	-	13,911	(6,071)	7,840
Current Risk Management Liabilities	7,583	65	-	7,648	(5,820)	1,828
Long-term Risk Management Liabilities	2,970	-	-	2,970	(865)	2,105
Total Liabilities	10,553	65	-	10,618	(6,685)	3,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,273	$ 20	$ -	$ 3,293	$ 614	$ 3,907

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

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

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

The table below presents KPCo's activity of derivative risk management contracts for the three and six months ended June 30, 2014 and 2013:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three and Six Months Ended June 30, 2014 and 2013

	Three Months Ended June 30,		Six Months Ended June 30,	
Location of Gain (Loss)	**2014**	**2013**	**2014**	**2013**
	(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 904	$ (150)	$ 7,844	$ 446
Fuel and Other Consumables Used for Electric Generation	7	-	8	-
Regulatory Assets (a)	-	-	-	-
Regulatory Liabilities (a)	1,816	298	2,936	(169)
Total Gain on Risk Management Contracts	$ 2,727	$ 148	$ 10,788	$ 277

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. 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 Expense on KPCo's condensed statements of income. During the three and six months ended June 30, 2014 and 2013, 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 (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and six months ended June 30, 2014 and 2013, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. During the three and six months ended June 30, 2013, KPCo designated heating oil and gasoline derivatives as cash flow hedges. KPCo discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2014 and 2013, 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 (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and six months ended June 30, 2014 and 2013, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During the three and six months ended June 30, 2014 and 2013, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2014 and 2013, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of June 30, 2014 and December 31, 2013 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
June 30, 2014

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ -	$ -	$ -
Hedging Liabilities (a)	-	-	-
AOCI Loss Net of Tax	-	(191)	(191)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	-	(60)	(60)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 79	$ -	$ 79
Hedging Liabilities (a)	59	-	59
AOCI Gain (Loss) Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of June 30, 2014, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (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 June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 29	$ 118
Amount of Collateral KPCo Would Have Been Required to Post	635	565
Amount Attributable to RTO and ISO Activities	621	522

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of June 30, 2014 and December 31, 2013:

	June 30, 2014	December 31, 2013
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 2,224	$ 4,039
Amount of Cash Collateral Posted	-	-
Additional Settlement Liability if Cross Default Provision is Triggered	1,628	3,817

9. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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

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

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo's Long-term Debt as of June 30, 2014 and December 31, 2013 are summarized in the following table:

	June 30, 2014		December 31, 2013	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 814,472	$ 928,848	$ 749,389	$ 841,594

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2014 and December 31, 2013. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
June 30, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 53	$ 6,234	$ 3,979	$ (3,238)	$ 7,028
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 41	$ 4,344	$ 393	$ (3,120)	$ 1,658

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Cash Flow Hedges:					
Commodity Hedges (a)	-	85	-	(6)	79
Total Risk Management Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Cash Flow Hedges:					
Commodity Hedges (a)	-	65	-	(6)	59
Total Risk Management Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

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

There were no transfers between Level 1 and Level 2 during the three and six months ended June 30, 2014 and 2013.

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

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

Three Months Ended June 30, 2013	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of March 31, 2013	$ 1,804
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(76)
Purchases, Issuances and Settlements (c)	132
Transfers into Level 3 (d) (e)	50
Transfers out of Level 3 (e) (f)	(75)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	839
Balance as of June 30, 2013	$ 2,674

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

Six Months Ended June 30, 2013	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(725)
Purchases, Issuances and Settlements (c)	591
Transfers into Level 3 (d) (e)	177
Transfers out of Level 3 (e) (f)	(191)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	623
Balance as of June 30, 2013	$ 2,674

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of June 30, 2014 and December 31, 2013:

Significant Unobservable Inputs
June 30, 2014

	Fair Value			Significant	Forward Price Range		
	Assets	Liabilities	Valuation Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 1,094	$ 364	Discounted Cash Flow	Forward Market Price	$ 13.59	$ 66.90	$ 42.23
FTRs	2,885	29	Discounted Cash Flow	Forward Market Price	(14.63)	9.26	1.01
Total	$ 3,979	$ 393					

Significant Unobservable Inputs
December 31, 2013

	Fair Value				Forward Price Range	
	Assets	Liabilities	Valuation Technique	Significant Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of June 30, 2014:

Sensitivity of Fair Value Measurements
June 30, 2014

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

10. INCOME TAXES

AEP System Tax Allocation Agreement

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

Federal and State Income Tax Audit Status

The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. The IRS examination of years 2011 and 2012 started in April 2014. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

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

11. FINANCING ACTIVITIES

Long-term Debt

A long-term debt issuance during the first six months of 2014 is shown in the table below:

Type of Debt	Principal Amount (a)	Interest Rate	Due Date
	(in thousands)	(%)	
Pollution Control Bonds	$ 65,000 (b)	Variable	2036

(a) Amount indicated on the statement of cash flows is net of issuance costs and premium or discount and will not tie to the issuance amount.
(b) Pollution Control Bond is subject to redemption earlier than the maturity date. Consequently, this bond has been classified for maturity purposes as Long-term Debt Due Within One Year – Nonaffiliated.

Dividend Restrictions

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

Federal Power Act

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

Leverage Restrictions

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

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of June 30, 2014 and December 31, 2013 are included in Advances to Affiliates and Advances from Affiliates, respectively, on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the six months ended June 30, 2014 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Loans to the Utility Money Pool as of June 30, 2014	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 50,366	$ 50,332	$ 24,601	$ 35,824	$ 49,348	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the six months ended June 30, 2014 and 2013 are summarized in the following table:

Six Months Ended June 30,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2014	0.33 %	0.24 %	0.33 %	0.26 %	0.28 %	0.31 %
2013	0.43 %	0.35 %	0.36 %	0.32 %	0.38 %	0.34 %

Sale of Receivables – AEP Credit

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

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

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $54 million and $43 million as of June 30, 2014 and December 31, 2013, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended June 30, 2014 and 2013 were $633 thousand and $481 thousand, respectively, and for the six months ended June 30, 2014 and 2013 were $1.4 million and $1 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended June 30, 2014 and 2013 were $141 million and $128 million, respectively, and for the six months ended June 30, 2014 and 2013 were $320 million and $268 million, respectively.

12. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of

AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended June 30, 2014 and 2013 were $12 million and $8 million, respectively, and for the six months ended June 30, 2014 and 2013 were $25 million and $15 million, respectively. The carrying amount of liabilities associated with AEPSC as of June 30, 2014 and December 31, 2013 was $4 million and $4 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended June 30, 2014 and 2013 were $28 million and $23 million, respectively, and for the six months ended June 30, 2014 and 2013 were $58 million and $48 million, respectively. The carrying amount of liabilities associated with AEGCo as of June 30, 2014 and December 31, 2013 was $10 million and $11 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

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Kentucky Power Company

2014 Third Quarter Report

Financial Statements

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GLOSSARY OF TERMS

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
REVENUES				
Electric Generation, Transmission and Distribution	$ 198,477	$ 182,950	$ 631,212	$ 544,225
Sales to AEP Affiliates	404	28,415	7,094	79,051
Other Revenues	201	171	469	453
TOTAL REVENUES	199,082	211,536	638,775	623,729
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	77,584	48,574	229,552	161,056
Purchased Electricity for Resale	773	2,523	5,943	8,833
Purchased Electricity from AEP Affiliates	28,526	77,594	87,886	193,502
Other Operation	19,555	18,699	58,360	53,994
Maintenance	16,082	17,197	52,448	52,731
Asset Impairments and Other Related Charges	—	32,847	—	32,847
Depreciation and Amortization	24,168	22,850	70,723	68,621
Taxes Other Than Income Taxes	5,129	5,296	15,719	15,368
TOTAL EXPENSES	171,817	225,580	520,631	586,952
OPERATING INCOME (LOSS)	27,265	(14,044)	118,144	36,777
Other Income (Expense):				
Interest Income	134	45	214	289
Allowance for Equity Funds Used During Construction	770	511	3,486	1,176
Interest Expense	(9,505)	(12,218)	(27,847)	(35,296)
INCOME (LOSS) BEFORE INCOME TAX EXPENSE (CREDIT)	18,664	(25,706)	93,997	2,946
Income Tax Expense (Credit)	6,863	(9,193)	34,390	71
NET INCOME (LOSS)	$ 11,801	$ (16,513)	$ 59,607	$ 2,875

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

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Three and Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Net Income (Loss)	$ 11,801	$ (16,513)	$ 59,607	$ 2,875
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES				
Cash Flow Hedges, Net of Tax of $8 and $17 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $12 and $89 for the Nine Months Ended September 30, 2014 and 2013, Respectively	15	(31)	23	165
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $64 and $134 for the Three Months Ended September 30, 2014 and 2013, Respectively, and $189 and $416 for the Nine Months Ended September 30, 2014 and 2013, Respectively	118	248	351	773
TOTAL OTHER COMPREHENSIVE INCOME	133	217	374	938
TOTAL COMPREHENSIVE INCOME (LOSS)	$ 11,934	$ (16,296)	$ 59,981	$ 3,813

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2012	$ 50,450	$ 531,536	$ 190,819	$ (19,994)	$ 752,811
Capital Contribution from Parent		78,781			78,781
Common Stock Dividends			(14,233)		(14,233)
Net Income			2,875		2,875
Other Comprehensive Income				938	938
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2013	$ 50,450	$ 610,317	$ 179,461	$ (19,056)	$ 821,172
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2013	$ 50,450	$ 614,648	$ 179,691	$ (5,420)	$ 839,369
Capital Contribution Returned to Parent		(100,000)			(100,000)
Common Stock Dividends			(100,000)		(100,000)
Other Changes in Common Shareholder's Equity		2,812			2,812
Net Income			59,607		59,607
Other Comprehensive Income				374	374
Pension and OPEB Adjustment Related to Kammer Plant				(1,308)	(1,308)
TOTAL COMMON SHAREHOLDER'S EQUITY - SEPTEMBER 30, 2014	$ 50,450	$ 517,460	$ 139,298	$ (6,354)	$ 700,854

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2014 and December 31, 2013
(in thousands)
(Unaudited)

	September 30, 2014	December 31, 2013
CURRENT ASSETS		
Cash and Cash Equivalents	$ 654	$ 743
Advances to Affiliates	9,577	—
Accounts Receivable:		
Customers	7,650	17,889
Affiliated Companies	34,809	9,781
Accrued Unbilled Revenues	—	857
Miscellaneous	98	75
Allowance for Uncollectible Accounts	(25)	(78)
Total Accounts Receivable	42,532	28,524
Fuel	35,828	92,313
Materials and Supplies	35,852	43,940
Risk Management Assets	4,346	4,356
Accrued Tax Benefits	—	5,249
Regulatory Asset for Under-Recovered Fuel Costs	8,990	—
Prepayments and Other Current Assets	3,815	3,284
TOTAL CURRENT ASSETS	141,594	178,409
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	1,148,473	1,052,757
Transmission	521,653	507,844
Distribution	717,882	693,481
Other Property, Plant and Equipment (Including Plant to be Retired)	512,234	480,759
Construction Work in Progress	80,211	128,599
Total Property, Plant and Equipment	2,980,453	2,863,440
Accumulated Depreciation and Amortization	1,003,004	943,889
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,977,449	1,919,551
OTHER NONCURRENT ASSETS		
Regulatory Assets	218,681	216,360
Long-term Risk Management Assets	1,336	3,484
Employee Benefits and Pension Assets	16,075	11,446
Deferred Charges and Other Noncurrent Assets	7,955	20,207
TOTAL OTHER NONCURRENT ASSETS	244,047	251,497
TOTAL ASSETS	$ 2,363,090	$ 2,349,457

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

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND COMMON SHAREHOLDER'S EQUITY
September 30, 2014 and December 31, 2013
(Unaudited)

	September 30, 2014	December 31, 2013
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ —	$ 8,564
Accounts Payable:		
General	66,426	21,619
Affiliated Companies	29,070	39,171
Long-term Debt Due Within One Year – Nonaffiliated	65,000	—
Long-term Debt Due Within One Year – Affiliated	20,000	—
Risk Management Liabilities	2,084	1,828
Customer Deposits	25,568	25,211
Deferred Income Taxes	7,375	6,486
Accrued Taxes	39,298	20,801
Accrued Interest	5,564	6,678
Regulatory Liability for Over-Recovered Fuel Costs	—	2,851
Other Current Liabilities	24,045	19,411
TOTAL CURRENT LIABILITIES	284,430	152,620
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	729,514	729,389
Long-term Debt – Affiliated	—	20,000
Long-term Risk Management Liabilities	615	2,105
Deferred Income Taxes	545,594	549,672
Regulatory Liabilities and Deferred Investment Tax Credits	22,596	22,926
Asset Retirement Obligations	64,113	20,526
Employee Benefits and Pension Obligations	7,864	6,041
Deferred Credits and Other Noncurrent Liabilities	7,510	6,809
TOTAL NONCURRENT LIABILITIES	1,377,806	1,357,468
TOTAL LIABILITIES	1,662,236	1,510,088
Rate Matters (Note 4)		
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	517,460	614,648
Retained Earnings	139,298	179,691
Accumulated Other Comprehensive Income (Loss)	(6,354)	(5,420)
TOTAL COMMON SHAREHOLDER'S EQUITY	700,854	839,369
TOTAL LIABILITIES AND COMMON SHAREHOLDER'S EQUITY	$ 2,363,090	$ 2,349,457

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

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2014 and 2013
(in thousands)
(Unaudited)

	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
OPERATING ACTIVITIES		
Net Income	$ 59,607	$ 2,875
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	70,723	68,621
Deferred Income Taxes	(3,594)	(12,929)
Asset Impairments and Other Related Charges	—	32,847
Allowance for Equity Funds Used During Construction	(3,486)	(1,176)
Mark-to-Market of Risk Management Contracts	904	1,756
Pension Contributions to Qualified Plan Trust	(1,923)	—
Property Taxes	10,448	10,013
Fuel Over/Under-Recovery, Net	(11,841)	(2,346)
Change in Other Noncurrent Assets	(2,826)	674
Change in Other Noncurrent Liabilities	4,616	4,179
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	(14,008)	27,461
Fuel, Materials and Supplies	64,573	20,494
Accounts Payable	27,984	(44,169)
Accrued Taxes, Net	24,044	(3,946)
Accrued Interest	(1,114)	(6,505)
Other Current Assets	(621)	2,160
Other Current Liabilities	5,184	(5,573)
Net Cash Flows from Operating Activities	228,670	94,436
INVESTING ACTIVITIES		
Construction Expenditures	(73,505)	(94,354)
Change in Advances to Affiliates, Net	(9,577)	(6,300)
Acquisitions of Assets	(1,186)	(63)
Proceeds from Sales of Assets	228	5,549
Other Investing Activities	384	—
Net Cash Flows Used for Investing Activities	(83,656)	(95,168)
FINANCING ACTIVITIES		
Capital Contribution from (Returned to) Parent	(100,000)	78,781
Issuance of Long-term Debt – Nonaffiliated	183,970	199,700
Change in Advances from Affiliates, Net	(8,564)	(13,359)
Retirement of Long-term Debt – Nonaffiliated	(120,000)	(250,000)
Principal Payments for Capital Lease Obligations	(1,786)	(1,036)
Dividends Paid on Common Stock	(100,000)	(14,233)
Other Financing Activities	1,277	242
Net Cash Flows from (Used for) Financing Activities	(145,103)	95
Net Decrease in Cash and Cash Equivalents	(89)	(637)
Cash and Cash Equivalents at Beginning of Period	743	1,482
Cash and Cash Equivalents at End of Period	$ 654	$ 845
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 28,111	$ 40,774
Net Cash Paid for Income Taxes	6,564	7,703
Noncash Acquisitions Under Capital Leases	1,273	1,120
Construction Expenditures Included in Current Liabilities as of September 30,	13,855	27,457

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

INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. SIGNIFICANT ACCOUNTING MATTERS

General

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

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2014 is not necessarily indicative of results that may be expected for the year ending December 31, 2014. The condensed financial statements are unaudited and should be read in conjunction with the audited 2013 financial statements and notes thereto, which are included in KPCo's 2013 Annual Report.

Management reviewed subsequent events through October 23, 2014, the date that the third quarter 2014 report was issued.

Revenue Recognition

Electricity Supply and Delivery Activities - Transactions with PJM

Revenues are recognized 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.

KPCo sells power produced at its generation plants to PJM and purchases power from PJM to supply its retail load. These power sales and purchases for retail load are netted hourly for financial reporting purposes. On an hourly net basis, KPCo records sales of power to PJM in excess of purchases of power from PJM as revenues on the statements of income. Also, on an hourly net basis, KPCo records purchases of power from PJM to serve retail load in excess of sales of power to PJM as Purchased Electricity for Resale on the statements of income. Upon termination of the Interconnection Agreement in 2014, KPCo manages and accounts for its purchases and sales with PJM individually based on market prices.

Asset Retirement Obligations (ARO)

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

The following is a reconciliation of the September 30, 2014 aggregate carrying amount of ARO for KPCo:

ARO as of December 31, 2013	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO as of September 30, 2014
		(in thousands)			
$ 20,526	$ 1,475	$ 42,578	$ (466)	$ —	$ 64,113

2. NEW ACCOUNTING PRONOUNCEMENTS

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

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

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

The new accounting guidance is effective for interim and annual periods beginning after December 15, 2014 with early adoption permitted. If applicable, this standard will change the presentation of financial statements but will not affect the calculation of net income, comprehensive income or earnings per share.

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

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

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

3. COMPREHENSIVE INCOME

Presentation of Comprehensive Income

The following tables provide the components of changes in AOCI for the three and nine months ended September 30, 2014 and 2013. All amounts in the following tables are presented net of related income taxes.

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

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

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Three Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of June 30, 2013	$ 39	$ (252)	$ (19,060)	$ (19,273)
Change in Fair Value Recognized in AOCI	(7)	—	—	(7)
Amounts Reclassified from AOCI	(39)	15	248	224
Net Current Period Other Comprehensive Income	(46)	15	248	217
Balance in AOCI as of September 30, 2013	$ (7)	$ (237)	$ (18,812)	$ (19,056)

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

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

Changes in Accumulated Other Comprehensive Income (Loss) by Component
For the Nine Months Ended September 30, 2013

	Cash Flow Hedges			
	Commodity	Interest Rate and Foreign Currency	Pension and OPEB	Total
	(in thousands)			
Balance in AOCI as of December 31, 2012	$ (127)	$ (282)	$ (19,585)	$ (19,994)
Change in Fair Value Recognized in AOCI	132	—	—	132
Amounts Reclassified from AOCI	(12)	45	773	806
Net Current Period Other Comprehensive Income	120	45	773	938
Balance in AOCI as of September 30, 2013	$ (7)	$ (237)	$ (18,812)	$ (19,056)

Reclassifications from Accumulated Other Comprehensive Income

The following tables provide details of reclassifications from AOCI for the three and nine months ended September 30, 2014 and 2013. The amortization of pension and OPEB AOCI components are included in the computation of net periodic pension and OPEB costs. See Note 7 for additional details.

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Three Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI	
	Three Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$ —	$ (70)
Purchased Electricity for Resale	—	20
Other Operation Expense	—	(3)
Maintenance Expense	—	(3)
Property, Plant and Equipment	—	(4)
Subtotal – Commodity	—	(60)
Interest Rate and Foreign Currency:		
Interest Expense	23	23
Subtotal – Interest Rate and Foreign Currency	23	23
Reclassifications from AOCI, before Income Tax (Expense) Credit	23	(37)
Income Tax (Expense) Credit	8	(13)
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	15	(24)
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(55)	(91)
Amortization of Actuarial (Gains)/Losses	236	472
Reclassifications from AOCI, before Income Tax (Expense) Credit	181	381
Income Tax (Expense) Credit	63	133
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	118	248
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 133	$ 224

Reclassifications from Accumulated Other Comprehensive Income (Loss)
For the Nine Months Ended September 30, 2014 and 2013

	Amount of (Gain) Loss Reclassified from AOCI	
	Nine Months Ended September 30,	
	2014	2013
Gains and Losses on Cash Flow Hedges	(in thousands)	
Commodity:		
Electric Generation, Transmission and Distribution Revenues	$ —	$ (39)
Purchased Electricity for Resale	(512)	44
Other Operation Expense	(3)	(8)
Maintenance Expense	(5)	(5)
Property, Plant and Equipment	(6)	(10)
Regulatory Assets/(Liabilities), Net (a)	(43)	—
Subtotal – Commodity	(569)	(18)
Interest Rate and Foreign Currency:		
Interest Expense	69	69
Subtotal – Interest Rate and Foreign Currency	69	69
Reclassifications from AOCI, before Income Tax (Expense) Credit	(500)	51
Income Tax (Expense) Credit	(175)	18
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	(325)	33
Pension and OPEB		
Amortization of Prior Service Cost (Credit)	(162)	(273)
Amortization of Actuarial (Gains)/Losses	702	1,461
Reclassifications from AOCI, before Income Tax (Expense) Credit	540	1,188
Income Tax (Expense) Credit	189	415
Reclassifications from AOCI, Net of Income Tax (Expense) Credit	351	773
Total Reclassifications from AOCI, Net of Income Tax (Expense) Credit	$ 26	$ 806

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

4. RATE MATTERS

As discussed in KPCo's 2013 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2013 Annual Report should be read in conjunction with this report to gain a complete understanding of material rate matters still pending that could impact net income, cash flows and possibly financial condition. The following discusses ratemaking developments in 2014 and updates KPCo's 2013 Annual Report.

Regulatory Assets Pending Final Regulatory Approval

Noncurrent Regulatory Assets	September 30, 2014	December 31, 2013
	(in thousands)	
Regulatory Assets Currently Not Earning a Return		
Storm Related Costs	$ 12,146	$ 12,146
Total Regulatory Assets Pending Final Regulatory Approval	$ 12,146	$ 12,146

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

Plant Transfer

In 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. KPCo also requested that costs related to the Big Sandy Plant, Unit 2 FGD project be established as a regulatory asset. As of September 30, 2014, the net book value of Big Sandy Plant, Unit 2 was $273 million, before cost of removal, including materials and supplies inventory and CWIP.

In October 2013, the KPSC issued an order approving a modified settlement agreement between KPCo, Kentucky Industrial Utility Customers, Inc. and the Sierra Club. The modified settlement approved the transfer of a one-half interest in the Mitchell Plant to KPCo at net book value on December 31, 2013 with the limitation that the net book value of the Mitchell Plant transfer not exceed the amount to be determined by a WVPSC order. The WVPSC order was subsequently issued in December 2013, but the WVPSC deferred a decision on the transfer of the one-half interest in the Mitchell Plant to APCo. The settlement also included the implementation of an Asset Transfer Rider to collect $44 million annually effective January 2014, subject to true-up, and allowed KPCo to retain any off-system sales margins above the $15.3 million annual level in base rates. Additionally, the settlement allows for KPCo to file a Certificate of Public Convenience and Necessity to convert Big Sandy Plant, Unit 1 to natural gas, provided the cost is approximately $60 million, and addressed potential greenhouse gas initiatives on the Mitchell Plant. The settlement also approved recovery, including a return, of coal-related retirement costs related to Big Sandy Plant over 25 years when base rates are set in the next base rate case (no earlier than June 2015), but rejected KPCo's request to defer FGD project costs for Big Sandy Plant, Unit 2. In December 2013, the transfer of a one-half interest in the Mitchell Plant to KPCo was completed.

In December 2013, the Attorney General filed an appeal with the Franklin County Circuit Court. In May 2014, KPCo's motion to dismiss the appeal was denied. In May 2014, KPCo filed motions for reconsideration and clarification with the Franklin County Circuit Court. In June 2014, the motion for reconsideration was denied but the motion to clarify was granted, thereby limiting the appeal to the issues of law presented in the Attorney General's appeal. If any part of the KPSC order is overturned, or if the WVPSC approves a lower net book value for the Mitchell Plant transfer, it could reduce future net income and cash flows and impact financial condition.

Kentucky Fuel Adjustment Clause Review

In August 2014, the KPSC issued an order initiating a review of KPCo's FAC from November 2013 through April 2014. An intervenor has requested and received a revised procedural schedule to determine if the allocation of fuel costs has been applied appropriately. In October 2014, intervenors filed testimony that recommended the KPSC direct KPCo to modify its fuel allocation methodology and order a refund to customers of approximately $13 million, plus carrying charges at a weighted average cost of capital, related to the period January 1, 2014 through April 30, 2014. A hearing at the KPSC is scheduled for November 2014. Management believes the methodology used to determine fuel costs is appropriate and intends to oppose the recommendations filed by intervenors. If the KPSC directs KPCo to modify its fuel allocation methodology, it could affect the allocation of costs for all periods beginning January 2014, and if any of these costs are not recoverable, it could reduce future net income and cash flows and impact financial condition.

5. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, KPCo's business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material effect on the financial statements. The Commitments, Guarantees and Contingencies note within KPCo's 2013 Annual Report should be read in conjunction with this report.

GUARANTEES

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

Letter of Credit

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. As of September 30, 2014, 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 conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. Under the lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance. As of September 30, 2014, the maximum potential loss for these lease agreements was approximately $1.3 million assuming the fair value of the equipment is zero at the end of the lease term.

6. IMPAIRMENT

2013

Big Sandy Plant, Unit 2 FGD Project

In the third quarter of 2013, KPCo recorded a pretax write-off of $33 million in Asset Impairments and Other Related Charges on the statement of income primarily related to the Big Sandy Plant, Unit 2 FGD project. See the "Plant Transfer" section of Rate Matters in Note 4.

7. BENEFIT PLANS

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

Components of Net Periodic Benefit Cost

The following tables provide the components of KPCo's net periodic benefit cost (credit) for the plans for the three and nine months ended September 30, 2014 and 2013:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$ 574	$ 471	$ 118	$ 208
Interest Cost	2,010	1,827	602	643
Expected Return on Plan Assets	(2,418)	(2,564)	(1,061)	(1,030)
Amortization of Prior Service Cost (Credit)	15	14	(606)	(611)
Amortization of Net Actuarial Loss	1,117	1,650	187	588
Net Periodic Benefit Cost (Credit)	$ 1,298	$ 1,398	$ (760)	$ (202)

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
	(in thousands)			
Service Cost	$ 1,724	$ 1,411	$ 354	$ 624
Interest Cost	6,031	5,480	1,804	1,928
Expected Return on Plan Assets	(7,255)	(7,691)	(3,180)	(3,091)
Amortization of Prior Service Cost (Credit)	43	43	(1,818)	(1,832)
Amortization of Net Actuarial Loss	3,350	4,951	560	1,764
Net Periodic Benefit Cost (Credit)	$ 3,893	$ 4,194	$ (2,280)	$ (607)

8. BUSINESS SEGMENTS

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

9. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

KPCo is exposed to certain market risks as a major power producer and marketer of wholesale electricity, natural gas, coal and emission allowances. These risks include commodity price risk, interest rate risk, 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 extent, heating oil, gasoline and other commodity contracts to manage the risk associated with the energy business. AEPSC, on behalf of KPCo, enters into interest rate derivative contracts in order to manage the interest rate exposure associated with KPCo’s commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as these risks are related to energy risk management activities. AEPSC, on behalf of KPCo, also engages in risk management of interest rate risk associated with debt 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 the KPCo’s outstanding derivative contracts as of September 30, 2014 and December 31, 2013:

Notional Volume of Derivative Instruments

	Volume		
	September 30, 2014	**December 31, 2013**	**Unit of Measure**
	(in thousands)		
Commodity:			
Power	9,901	10,071	MWhs
Coal	193	2	Tons
Natural Gas	167	509	MMBtus
Heating Oil and Gasoline	237	261	Gallons
Interest Rate	$ 1,417	$ 2,615	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 and natural gas ("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. Cash flow hedge accounting for these derivative contracts was discontinued effective March 31, 2014. For disclosure purposes, these contracts were included with other hedging activities as "Commodity" as of December 31, 2013. In March 2014, these contracts were grouped as "Commodity" with other risk management activities. KPCo does not hedge all fuel price risk.

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. 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 condensed balance sheets at fair value. The fair values of derivative instruments accounted for using MTM accounting or hedge accounting are based on exchange prices and broker quotes. If a quoted market price is not available, the estimate of fair value is based on the best information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and assumptions. In order to determine the relevant fair values of the derivative instruments, KPCo applies valuation adjustments for discounting, liquidity and credit quality.

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

According to the accounting guidance for "Derivatives and Hedging," KPCo reflects the fair values of derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2014 and December 31, 2013 condensed balance sheets, KPCo netted $47 thousand and $0 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $93 thousand and $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 KPCo's derivative activity on the condensed balance sheets as of September 30, 2014 and December 31, 2013:

Fair Value of Derivative Instruments
September 30, 2014

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 6,384	$ —	$ —	$ 6,384	$ (2,038)	$ 4,346
Long-term Risk Management Assets	1,631	—	—	1,631	(295)	1,336
Total Assets	8,015	—	—	8,015	(2,333)	5,682
Current Risk Management Liabilities	4,202	—	—	4,202	(2,118)	2,084
Long-term Risk Management Liabilities	876	—	—	876	(261)	615
Total Liabilities	5,078	—	—	5,078	(2,379)	2,699
Total MTM Derivative Contract Net Assets (Liabilities)	$ 2,937	$ —	$ —	$ 2,937	$ 46	$ 2,983

Fair Value of Derivative Instruments
December 31, 2013

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Gross Amounts of Risk Management Assets/ Liabilities Recognized	Gross Amounts Offset in the Statement of Financial Position (b)	Net Amounts of Assets/Liabilities Presented in the Statement of Financial Position (c)
			(in thousands)			
Current Risk Management Assets	$ 9,520	$ 85	$ —	$ 9,605	$ (5,249)	$ 4,356
Long-term Risk Management Assets	4,306	—	—	4,306	(822)	3,484
Total Assets	13,826	85	—	13,911	(6,071)	7,840
Current Risk Management Liabilities	7,583	65	—	7,648	(5,820)	1,828
Long-term Risk Management Liabilities	2,970	—	—	2,970	(865)	2,105
Total Liabilities	10,553	65	—	10,618	(6,685)	3,933
Total MTM Derivative Contract Net Assets (Liabilities)	$ 3,273	$ 20	$ —	$ 3,293	$ 614	$ 3,907

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

The table below presents KPCo's activity of derivative risk management contracts for the three and nine months ended September 30, 2014 and 2013:

Amount of Gain (Loss) Recognized on Risk Management Contracts For the Three and Nine Months Ended September 30, 2014 and 2013

Location of Gain (Loss)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
	(in thousands)			
Electric Generation, Transmission and Distribution Revenues	$ 2,963	$ 714	$ 10,807	$ 1,160
Fuel and Other Consumables Used for Electric Generation	(3)	—	5	—
Regulatory Assets (a)	(1,493)	—	(1,236)	—
Regulatory Liabilities (a)	(1,314)	(775)	1,365	(944)
Total Gain (Loss) on Risk Management Contracts	$ 153	$ (61)	$ 10,941	$ 216

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

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

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

For contracts that have not been designated as part of a hedging relationship, the accounting for changes in fair value depends on whether the derivative instrument is held for trading purposes. Unrealized and realized gains and losses on derivative instruments held for trading purposes are included in revenues on a net basis on KPCo's condensed statements of income. Unrealized and realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses on KPCo's condensed statements of income depending on the relevant facts and circumstances. 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 Expense on KPCo's condensed statements of income. During the three and nine months ended September 30, 2014 and 2013, 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 (Loss) on the condensed balance sheets until the period the hedged item affects Net Income. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal and natural gas designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's condensed statements of income, or in Regulatory Assets or Regulatory Liabilities on KPCo's condensed balance sheets, depending on the specific nature of the risk being hedged. During the three and nine months ended September 30, 2014 and 2013, KPCo designated power, coal and natural gas derivatives as cash flow hedges.

KPCo reclassifies gains and losses on heating oil and gasoline derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its condensed balance sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the condensed statements of income. KPCo discontinued cash flow hedge accounting for these derivative contracts effective March 31, 2014. During the three and nine months ended September 30, 2013, 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 (Loss) on its condensed balance sheets into Interest Expense on its condensed statements of income in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2014 and 2013, 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 (Loss) on KPCo's condensed balance sheets into Depreciation and Amortization expense on the condensed statements of income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During the three and nine months ended September 30, 2014 and 2013, KPCo did not designate any foreign currency derivatives as cash flow hedges.

During the three and nine months ended September 30, 2014 and 2013, hedge ineffectiveness was immaterial or nonexistent for all cash flow hedge strategies disclosed above.

For details on designated, effective cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2014 and 2013, see Note 3.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's condensed balance sheets as of September 30, 2014 and December 31, 2013 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2014

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ —	$ —	$ —
Hedging Liabilities (a)	—	—	—
AOCI Loss Net of Tax	—	(176)	(176)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	—	(60)	(60)

Impact of Cash Flow Hedges on the Condensed Balance Sheet
December 31, 2013

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 79	$ —	$ 79
Hedging Liabilities (a)	59	—	59
AOCI Gain (Loss) Net of Tax	23	(222)	(199)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	23	(60)	(37)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of September 30, 2014, KPCo is not hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") its exposure to variability in future cash flows related to forecasted transactions.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. KPCo has not experienced a downgrade below investment grade. The following table represents: (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 September 30, 2014 and December 31, 2013:

	September 30, 2014	December 31, 2013
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 32	$ 118
Amount of Collateral KPCo Would Have Been Required to Post	558	565
Amount Attributable to RTO and ISO Activities	554	522

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event by Parent or the obligor under outstanding debt or a third party obligation in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of September 30, 2014 and December 31, 2013:

	September 30, 2014	December 31, 2013
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 1,597	$ 4,039
Amount of Cash Collateral Posted	—	—
Additional Settlement Liability if Cross Default Provision is Triggered	1,484	3,817

10. FAIR VALUE MEASUREMENTS

Fair Value Hierarchy and Valuation Techniques

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

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

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo's Long-term Debt as of September 30, 2014 and December 31, 2013 are summarized in the following table:

	September 30, 2014		December 31, 2013	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 814,514	$ 932,434	$ 749,389	$ 841,594

Fair Value Measurements of Financial Assets and Liabilities

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2014 and December 31, 2013. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
September 30, 2014

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 39	$ 4,234	$ 3,535	$ (2,126)	$ 5,682
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 38	$ 4,469	$ 364	$ (2,172)	$ 2,699

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2013

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (b)	$ 170	$ 11,168	$ 2,487	$ (6,064)	$ 7,761
Cash Flow Hedges:					
Commodity Hedges (a)	—	85	—	(6)	79
Total Risk Management Assets	$ 170	$ 11,253	$ 2,487	$ (6,070)	$ 7,840
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (b)	$ 144	$ 10,092	$ 316	$ (6,678)	$ 3,874
Cash Flow Hedges:					
Commodity Hedges (a)	—	65	—	(6)	59
Total Risk Management Liabilities	$ 144	$ 10,157	$ 316	$ (6,684)	$ 3,933

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

There were no transfers between Level 1 and Level 2 during the three and nine months ended September 30, 2014 and 2013.

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

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

Three Months Ended September 30, 2013	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of June 30, 2013	$ 2,674
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(247)
Purchases, Issuances and Settlements (c)	(218)
Transfers into Level 3 (d) (e)	3
Transfers out of Level 3 (e) (f)	(3)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	39
Balance as of September 30, 2013	$ 2,248

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

Nine Months Ended September 30, 2013	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2012	$ 2,199
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(708)
Purchases, Issuances and Settlements (c)	354
Transfers into Level 3 (d) (e)	194
Transfers out of Level 3 (e) (f)	(187)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	396
Balance as of September 30, 2013	$ 2,248

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

The following tables quantify the significant unobservable inputs used in developing the fair value of Level 3 positions as of September 30, 2014 and December 31, 2013:

Significant Unobservable Inputs
September 30, 2014

	Fair Value		Valuation	Significant	Forward Price Range		
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High	Weighted Average
	(in thousands)						
Energy Contracts	$ 1,087	$ 332	Discounted Cash Flow	Forward Market Price	$ 12.55	$ 80.70	$ 41.68
FTRs	2,448	32	Discounted Cash Flow	Forward Market Price	(14.63)	15.47	1.38
Total	$ 3,535	$ 364					

Significant Unobservable Inputs
December 31, 2013

	Fair Value		Valuation	Significant	Forward Price Range	
	Assets	Liabilities	Technique	Unobservable Input (a)	Low	High
	(in thousands)					
Energy Contracts	$ 1,924	$ 198	Discounted Cash Flow	Forward Market Price	$ 13.04	$ 80.50
FTRs	563	118	Discounted Cash Flow	Forward Market Price	(5.10)	10.44
Total	$ 2,487	$ 316				

(a) Represents market prices in dollars per MWh.

The following table provides sensitivity of fair value measurements to increases (decreases) in significant unobservable inputs related to Energy Contracts and FTRs as of September 30, 2014:

Sensitivity of Fair Value Measurements
September 30, 2014

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

11. INCOME TAXES

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

The IRS examination of years 2009 and 2010 started in October 2011 and was completed in the second quarter of 2013. The IRS examination of years 2011 and 2012 started in April 2014. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to materially impact net income.

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

12. FINANCING ACTIVITIES

Long-term Debt

Long-term debt and other securities issued and retirements made during the first nine months of 2014 are shown in the tables below:

Type of Debt	Principal Amount (a)		Interest Rate	Due Date
Issuances:	**(in thousands)**		**(%)**	
Pollution Control Bonds	$ 65,000	(b)	Variable	2036
Senior Unsecured Notes	120,000		4.18	2026

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

(b) Pollution Control Bond is subject to redemption earlier than the maturity date. Consequently, this bond has been classified for maturity purposes as Long-term Debt Due Within One Year - Nonaffiliated.

Type of Debt	Principal Amount Paid	Interest Rate	Due Date
Retirements:	**(in thousands)**	**(%)**	
Other Long-term Debt	$ 120,000	Variable	2015

In December 2013, AGR assigned KPCo $200 million of Other Long-term Debt due in May 2015. In September 2014, KPCo refinanced $120 million of the original assignment as Senior Unsecured Notes (see issuances and retirements tables above). Also in September 2014, KPCo signed an agreement to refinance the remaining $80 million in December 2014 as 4.33% Senior Unsecured Notes due in 2026. Consequently and as of September 30, 2014, the remaining $80 million was excluded from current liabilities and was instead classified as Long-term Debt - Nonaffiliated on the balance sheet.

In October 2014, KPCo retired $20 million of 5.25% Notes Payable - Affiliated due in 2015.

Dividend Restrictions

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

Federal Power Act

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

Leverage Restrictions

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

Utility Money Pool - AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of AEP's subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions of the AEP System Utility Money Pool agreement filed with the FERC. The amounts of outstanding loans to (borrowings from) the Utility Money Pool as of September 30, 2014 and December 31, 2013 are included in Advances to Affiliates and Advances from Affiliates, respectively, on KPCo's condensed balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the nine months ended September 30, 2014 are described in the following table:

Maximum Borrowings from the Utility Money Pool	Maximum Loans to the Utility Money Pool	Average Borrowings from the Utility Money Pool	Average Loans to the Utility Money Pool	Loans to the Utility Money Pool as of September 30, 2014	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 50,366	$ 86,715	$ 23,837	$ 46,029	$ 9,577	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the nine months ended September 30, 2014 and 2013 are summarized in the following table:

Nine Months Ended September 30,	Maximum Interest Rate for Funds Borrowed from the Utility Money Pool	Minimum Interest Rate for Funds Borrowed from the Utility Money Pool	Maximum Interest Rate for Funds Loaned to the Utility Money Pool	Minimum Interest Rate for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2014	0.33%	0.24%	0.33%	0.26%	0.28%	0.28%
2013	0.43%	0.35%	0.36%	0.28%	0.38%	0.32%

Sale of Receivables - AEP Credit

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

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

KPCo's amounts of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement were $46 million and $43 million as of September 30, 2014 and December 31, 2013, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold for the three months ended September 30, 2014 and 2013 were $672 thousand and $493 thousand, respectively, and for the nine months ended September 30, 2014 and 2013 were $2.1 million and $1.5 million, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit for the three months ended September 30, 2014 and 2013 were $142 million and $130 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $462 million and $398 million, respectively.

13. VARIABLE INTEREST ENTITIES

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

AEPSC provides certain managerial and professional services to AEP's subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to the AEP subsidiary companies at AEPSC's cost. AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and any of the AEP subsidiaries that could require additional financial support from an AEP subsidiary or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. AEP subsidiaries are considered to have a significant interest in AEPSC due to their activity in AEPSC's cost reimbursement structure. However, AEP subsidiaries do not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. KPCo's total billings from AEPSC for the three months ended September 30, 2014 and 2013 were $12 million and $8 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $37 million and $23 million, respectively. The carrying amount of liabilities associated with AEPSC as of September 30, 2014 and December 31, 2013 was $4 million and $4 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant, Unit 1 and leases a 50% interest in Rockport Plant, Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP has agreed to provide AEGCo with the funds necessary to satisfy all of the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to these transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the three months ended September 30, 2014 and 2013 were $29 million and $28 million, respectively, and for the nine months ended September 30, 2014 and 2013 were $87 million and $76 million, respectively. The carrying amount of liabilities associated with AEGCo as of September 30, 2014 and December 31, 2013 was $10 million and $11 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

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Filing Requirement
807 KAR 5:001 Section 16 (4)(t)

Filing Requirement:

If the utility had amounts charged or allocated to it by an affiliate or general or home office or paid monies to an affiliate or general or home office during the test period or during the previous three (3) calendar years, the utility shall file:

1. ***A detailed description of the method and amounts allocated or charged to the utility by the affiliate or general or home office for each charge allocation or payment;***

2. ***An explanation of how the allocator for the test period was determined; and***

3. ***All facts relied upon, including other regulatory approval, to demonstrate that each amount charged, allocated, or paid during the test period was reasonable.***

Response:

1. Please see the attached document.

2-3. Amounts are allocated or charged in accordance with the Company's cost allocation manual developed and maintained in accordance with KRS 278.2203 and KRS 278.2205. A copy of the Company's current cost allocation manual is attached beginning at page 3 of this Section II.

Kentucky Power Company
AEPSC Billings to Kentucky Power Company Included in Cost of Service
Summary of Services Provided by Activity

Activity/Service Provided:	12 Months Ended September 30, 2014	12 Months Ended December 31, 2013	12 Months Ended December 31, 2012	12 Months Ended December 31, 2011
Design & Construct New Generating Facilities	$ 225,870	$ 26,682	$ 22,656	$ 77,263
Develop & Market Services for Unregulated Markets	117,472	44,855	117,345	172,081
Develop Distribution System Plan	372,529	418,450	435,658	545,383
Develop Regulated Business	95,924	98,265	58,137	54,085
Develop Transmission System Plan	52,322	59,373	44,954	41,698
Develop Wholesale Business	178,234	123,558	251,073	442,738
Develop/Deploy Info/Communication Systems	2,574,031	2,349,126	311,477	325,605
Engineer, Design & Construct Distribution Facilities	73,938	43,712	35,896	103,038
Engineer, Design & Construct Transmission Facilities	286,240	176,429	147,303	184,022
Ethics & Compliance Investigations	957	142	88	674
Maintain Plant	1,353,753	532,354	483,495	591,236
Manage & Operate Fossil & Hydro Generating Assets	1,947,182	955,024	1,076,392	737,553
Manage & Support Human Resources	3,314,675	1,876,129	1,226,947	992,632
Manage Accounting & Finance	1,776,787	441,704	1,936,829	1,555,407
Manage Corporate Relations & Governance	3,545,217	3,517,768	2,254,674	2,116,406
Manage Environmental Compliance	813,229	393,314	396,702	441,418
Manage NERC Compliance and Auditing	40,382	7,960	5,293	182
Manage Plant Safety & Compliance	219		104	
Manage SCR Operation and Maintenance Costs	54,299			
Manage Supply Chain	312,140	125,401	159,695	169,081
Operate & Maintain Distribution Facilities	425,307	301,289	535,566	552,116
Operate & Maintain Transmission Facilities	1,742,907	1,491,433	1,296,084	1,258,618
Operate Power Plants	128,798	146,735	180,424	269,959
Plan & Improve the Business	3,256,502	2,393,704	2,342,977	2,637,888
Plan Energy Generation	258,503	170,457	141,222	190,608
Procure, Produce & Deliver Fuel	72,403	6,773	7,073	10,756
Provide Corporate Support	1,493,180	1,235,440	841,754	1,130,612
Provide Internal Customer Service	919,673	839,150	963,675	1,093,704
Provide Retail and Wholesale Customer Service	2,794,488	2,589,071	3,739,620	4,385,311
Overhead Loading	601,589	390,246	535,722	171,263
Provide Shared Services	10,088	19,128	3,322,676	3,304,392
Grand Total	**$ 28,838,839**	**$ 20,773,670**	**$ 22,871,510**	**$ 23,555,732**

American Electric Power Service Corporation (AEPSC) is a wholly owned subsidiary of AEP and is the Centralized Service Company for the AEP System. AEPSC's activities are authorized by the FERC under the Public Utilities Holding Company Act of 2005. AEPSC performs, at cost, various corporate support services for subsidiaries of AEP, including Kentucky Power.

AEPSC transactions are accounted for through a work order system as required by the FERC. Expenditures for support services are accumulated in work orders and are billed to the company or companies benefiting from the service. Accounting within each work order is in accordance with the FERC Uniform System of Accounts. The costs for services benefiting only one company are directly assigned and are billed 100% to that company. Where services benefit more than one company, the costs for those services are allocated to the benefiting companies using an approved allocation factor. The allocation factor for any given allocation of costs is selected for use because it best reflects the cost driver associated with the service provided.

The FERC monitors the factors used for allocations, through required annual reporting, and can audit the validity of each factor. All services are billed at cost, with no profit charged, as required by the FERC's "at cost" rules.

Further information on the allocation of costs by AEPSC can be found in the Cost Allocation Manual, as filed in Case No. 2014-00396.

Kentucky Power Company
Amounts Charged to Kentucky Power by Affiliates Other than AEPSC
Included in Cost of Service

Affiliate	12 Months Ended September 30, 2014	12 Months Ended December 31, 2013	12 Months Ended December 31, 2012	12 Months Ended December 31, 2011
AEP Generation Resources	$ 5,470			
AEP Texas Central Company	24,914	14,193	9,974	2,305
AEP Texas North Company	10,185	10,148	4,300	5,930
AEP Transmission Company, LLC	10,605	10,630		
Appalachian Power Company	949,931	491,870	581,819	716,853
CSW Energy, Inc.	34,883			
Indiana Michigan Power Company	187,253	19,113	266,070	14,657
Kingsport Power Company	3,790	1,499	8,608	2,874
Ohio Power Company	201,854	414,033	540,565	413,109
Public Service Company of Oklahoma	26,840	21,522	46,552	(36,114)
Southwestern Electric Power Company	134,545	149,740	168,093	114,798
Wheeling Power Company	166	128	15,015	6,255
Cardinal Operating Company	16,240	15,136	953	
Other	984	917	30	
Total Amount Charged to KYP	**$ 1,607,660**	**$ 1,148,930**	**$ 1,641,978**	**$ 1,240,666**

Kentucky Power has a variety of transactions with affiliates on a normal basis. Transactions with affiliates generally fall into two categories. The first category, service payments, is a billing made when an affiliate provides a service to Kentucky Power, such as Appalachian Power providing assistance in distribution maintenance, or other affiliates providing assistance during storm recovery efforts. The second category, convenience payments, occurs when an affiliate company receives an invoice and the cost of that invoice should be borne by multiple AEP companies. For example, a legal invoice for a system-wide issue may be paid by one affiliate company, and that company then bills the other affiliates who benefit from the service.

Charges from affiliates are accumulated using a work order system. All affiliate services and convenience payments are billed to Kentucky Power at cost, per FERC affiliate requirements.

Filing Requirement
807 KAR 5:001 Section 16 (4)(u)

Filing Requirement:

If the utility provides gas, electric, water, or sewage utility service and has annual gross revenues greater than $5,000,000 a cost of service study based on a methodology generally accepted within the industry and based on current and reliable data from a single time period; and

Response:

Please see the testimony of Company Witnesses Stegall and Listebarger for the cost of service study based on current and reliable data from a single time period.

Filing Requirement
807 KAR 5:001 Section 16 (4)(v)

Filing Requirement:

Incumbent local exchange carriers with fewer than 50,000 access lines shall not be required to file cost of service studies, except as specifically directed by the commission. Local exchange carriers with more than 50,000 access lines shall file:

1. ***A jurisdictional separations study consistent with 47 C.F.R. Part 36; and***

2. ***Service specific cost studies to support the pricing of all services that generate annual revenue greater than $1,000,000 except local exchange access:***

    a. ***Based on current and reliable data from a single time period; and***

    b. ***Using generally recognized fully allocated, embedded, or incremental cost principles.***

Response:

Not Applicable.

Filing Requirement
807 KAR 5:001 Section 16 (5)(a)

Filing Requirement:

Upon good cause shown, a utility may request pro forma adjustments for known and measurable changes to ensure fair, just, and reasonable rates based on the historical test period. The following information shall be filed with each application requesting pro forma adjustments or a statement explaining why the required information does not exist and is not applicable to the utility's application:

(a) A detailed income statement and balance sheet reflecting the impact of all proposed adjustments;

Response:

Please see Section IV, pages 3, 4 and 7 of this filing.

Filing Requirement
807 KAR 5:001 Section 16 (5)(b)

Filing Requirement:

The most recent capital construction budget containing at least the period of time as proposed for any pro forma adjustment for plant additions;

Response:

The Company is not proposing any pro forma adjustments for plant additions. Please see the attached most recent capital construction budget.

Kentucky Power Company
November 20, 2014

Construction Expenditures by Function ($000's)	2015	2016	2017
Production	$ 43,544	$ 34,095	$ 21,451
Transmission	$ 12,109	$ 15,110	$ 12,296
Distribution	$ 38,881	$ 38,382	$ 36,918
General / Intangible Plant	$ 8,254	$ 4,955	$ 6,968
	$ 102,788	$ 92,542	$ 77,633

Source: 2014 EEI Capital Forecast

Filing Requirement
807 KAR 5:001 Section 16 (5)(c)

Filing Requirement:

For each proposed pro forma adjustment reflecting plant additions, provide the following information:

1. ***The starting date of the construction of each major component of plant;***

2. ***The proposed in-service date;***

3. ***The total estimated cost of construction at completion;***

4. ***The amount contained in construction work in progress at the end of the test period;***

5. ***A schedule containing a complete description of actual plant retirements and anticipated plant retirements related to the pro forma plant additions including the actual or anticipated date of retirement;***

6. ***The original cost and the cost of removal and salvage for each component of plant to be retired during the period of the proposed pro forma adjustment for plant additions;***

7. ***An explanation of differences, if applicable, in the amounts contained in the capital construction budget and the amounts of capital construction cost contained in the pro forma adjustment period; and***

8. ***The impact on depreciation expense of all proposed pro forma adjustments for plant additions and retirements;***

Response:

Not Applicable.

Filing Requirements 807 KAR 5:001 Section 16(6) to 807 KAR 5:001 Section 16 (8)(n) are Not Applicable.

Filing Requirement
807 KAR 5:001 Section 16(9)

Filing Requirement:

The commission shall notify the applicant of any deficiencies in the application within thirty (30) days of the application's submission. An application shall not be accepted for filing until the utility has cured all noted deficiencies.

Response:

Kentucky Power will promptly correct any deficiency from its application.

Filing Requirement
807 KAR 5:001 Section 16(10)

Filing Requirement:

A request for a waiver from the requirements of this section shall include the specific reasons for the request. The commission shall grant the request upon good cause shown by the utility. In determining if good cause has been shown, the commission shall consider:

(a) If other information that the utility would provide if the waiver is granted is sufficient to allow the commission to effectively and efficiently review the rate application;

(b) If the information that is the subject of the waiver request is normally maintained by the utility or reasonably available to it from the information that it maintains;

(c) The expense to the utility in providing the information that is the subject of the waiver request.

Response:

The Company is requesting no waivers at this time.

Filing Requirement
807 KAR 5:001 Section 17(1)(a)
807 KAR 5:011 Section 8 (1)(a)

Filing Requirement:

Public postings.

(a) A utility shall post at its place of business a copy of the notice no later than the date the application is submitted to the commission.

Response:

Kentucky Power Company will comply with 807 KAR 5:001, Section 17(1)(a) and 807 KAR 5:011 Section 8 (1)(a) by posting its Notice to the Customers of Kentucky Power Company on or before the day that the tariff is filed with the Public Service Commission at the locations shown below.

- **101A Enterprise Drive, Frankfort, Kentucky**
- **12333 Kevin Avenue, Ashland, Kentucky**
- **1400 E. Main Street, Hazard, Kentucky**
- **3249 North Mayo Trail, Pikeville, Kentucky**

The Notice will remain posted until issuance of a final order from the Commission establishing KPCo's approved rates.

Filing Requirement
807 KAR 5:001 Section 17(1)(b)
807 KAR 5:011 Section 8 (1)(b)

Filing Requirement:

Public postings.

(b) A utility that maintains a Web site shall, within five (5) business days of the date the application is submitted to the commission, post on its Web sites:

1. A copy of the public notice; and

2. A hyperlink to the location on the commission's Web site where the case documents are available.

Response:

Kentucky Power will within five (5) business days of filing its application post a copy of the public notice along with a hyperlink to the filing on the Commission's Web site. The Notice will remain posted until issuance of a final order from the Commission establishing KPCo's approved rates.

Filing Requirement
807 KAR 5:001 Section 17(1)(c)
807 KAR 5:011 Section 8 (1)(c)

Filing Requirement:

Public postings.

(d) The information required in paragraphs (a) and (b) of this subsection shall not be removed until the commission issues a final decision on the application.

Response:

The Company will comply with 807 KAR 5:001 Section 17(1)(c) and 807 KAR 5:011 Section 8 (1)(c).

Filing Requirement
807 KAR 5:001 Section 17(2)(b)
807 KAR 5:011 Section 8 (2)(b)

Filing Requirement:

Customer Notice.

(b) If a utility has more than twenty (20) customers, it shall provide notice by:

1. Including notice with customer bills mailed no later than the date the application is submitted to the commission;

2. Mailing a written notice to each customer no later than the date the application is submitted to the commission;

3. Publishing notice once a week for three (3) consecutive weeks in a prominent manner in a newspaper of general circulation in the utility's service area, the first publication to be made no later than the date the application is submitted to the commission; or

4. Publishing notice in a trade publication or newsletter delivered to all customers no later than the date the application is submitted to the commission.

(b) A utility that provides service in more than one (1) county may use a combination of the notice methods listed in paragraph (b) of this subsection.

Response:

Kentucky Power complied with 807 KAR 5:001 Section 17(2)(b)(3) and 807 KAR 5:011 Section 8(2)(b)(3) by delivering to newspapers of general circulation in its service territory a copy of the *Notice to the Customers of Kentucky Power Company* for publication once a week for three (3) consecutive weeks in a prominent manner, the first of said publications to be made by the date the application is filed.

Filing Requirement
807 KAR 5:001 Section 17(3)
807 KAR 5:011 Section 8(3)

Filing Requirement:

Proof of Notice. A utility shall file with the commission no later than forty-five (45) days from the date the application was initially submitted to the commission:

(a) If notice is mailed to its customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, that notice was mailed to all customers, and the date of the mailing;

(b) If notice is published in a newspaper of general circulation in the utility's service area, an affidavit from the publisher verifying the contents of the notice, that the notice was published, and the dates of the notice's publication; or

(c) If notice is published in a trade publication or newsletter delivered to all customers, an affidavit from an authorized representative of the utility verifying the contents of the notice, the mailing of the trade publication or newsletter, that notice was included in the publication or newsletter, and the date of mailing.

Response:

Kentucky Power Company will provide the prescribed affidavits within forty-five (45) days of the date of which Kentucky Power filed its application.

Filing Requirement
807 KAR 5:001 Section 17(4)(a)
807 KAR 5:011 Section 8(4)(a)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

(a) The proposed effective date and the date the proposed rates are expected to be filed with the commission;

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 17(4)(b)
807 KAR 5:011 Section 8(4)(b)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> ***The present rates and proposed rates for each customer classification to which the proposed rates will apply;***

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 17(4)(c)
807 KAR 5:011 Section 8(4)(c)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> ***The amount of the change requested in both dollar amounts and percentage change for each customer classification to which the proposed rates will apply;***

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 17(4)(d)
807 KAR 5:011 Section 8(4)(d)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> ***The amount of the average usage and the effect upon the average bill for each customer classification to which the proposed rates will apply, except for local exchange companies, which shall include the effect upon the average bill for each customer classification for the proposed rate change in basic local service;***

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 17(4)(e)
807 KAR 5:011 Section 8(4)(e)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> ***A statement that a person may examine this application at the offices of (utility name) located at (utility address);***

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 17(4)(f) and (g)
807 KAR 5:011 Section 8(4)(f) and (g)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> ***(f) A statement that a person may examine this application at the commission's offices located at 211 Sower Boulevard, Frankfort, Kentucky, Monday through Friday, 8:00 a.m. to 4:30 p.m., or through the commission's Web site at http://psc.ky.gov;***
>
> ***(g) A statement that comments regarding the application may be submitted to the Public Service Commission through its Web site or by mail to Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602;***

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 17(4)(h)
807 KAR 5:011 Section 8(4)(h)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> ***A statement that the rates contained in this notice are the rates proposed by (utility name) but that the Public Service Commission may order rates to be charged that differ from the proposed rates contained in this notice;***

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 17(4)(i)
807 KAR 5:011 Section 8(4)(i)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> ***A statement that a person may submit a timely written request for intervention to the Public Service Commission, Post Office Box 615, Frankfort, Kentucky 40602, establishing the grounds for the request including the status and interest of the party; and***

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 17(4)(j)
807 KAR 5:011 Section 8(4)(j)

Filing Requirement:

Notice Content. Each notice issued in accordance with this section shall contain:

> ***A statement that if the commission does not receive a written request for intervention within thirty (30) days of initial publication or mailing of the notice, the commission may take final action on the application.***

Response:

The notice complies with this requirement.

Filing Requirement
807 KAR 5:001 Section 16(3)
807 KAR 5:011 Section 8(5)

Filing Requirement:

Compliance by electric utilities with rate schedule information required by 807 KAR 5:051. Notice given pursuant to subsection (2)(a) or (b) of this section shall substitute for the notice required by 807 KAR 5:051, Section 2, if the notice contained a clear and concise explanation of the proposed change in the rate schedule applicable to each customer.

Response:

The Company has complied with 807 KAR 5:001 Section 16(3) and 807 KAR 5:011 Section 8(5).

Filing Requirement
807 KAR 5:011 Section 8(6)

Filing Requirement:

Periodic recalculation of a formulaic rate that does not involve a revision of the rate and that is performed in accordance with provisions of an effective rate schedule, special contract, or administrative regulation does not require notice in accordance with this section.

Response:

Not Applicable.

Filing Requirement
807 KAR 5:011 Section 9(1)

Filing Requirement:

The proposed rates on a new tariff or revised sheet of an existing tariff shall become effective on the date stated on the tariff sheet if:

(a) Proper notice was provided to the public in accordance with Section 8 of this administrative regulation;

(b) Statutory notice was provided; and

(c) The commission does not suspend the proposed rates pursuant to KRS 278.190.

Response:

The Company has complied with 807 KAR 5:011 Section 9(1).

Filing Requirement
807 KAR 5:011 Section 9(2)

Filing Requirement:

All information and notices required by this administrative regulation shall be furnished to the commission at the time of the filing of the proposed rate. If a substantial omission occurs, which is prejudicial to full consideration by the commission or to the public, the statutory notice period to the commission shall not commence until the omitted information and notice is filed.

Response:

Kentucky Power Company will comply with 807 KAR 5:011, Section 9(2) by including all information and notices required to the Commission at the time of filing. Kentucky Power will promptly correct any deficiency in its application.

Filing Requirement
807 KAR 5:051 Section 2(1)

Filing Requirement:

Each electric utility shall transmit to each of its consumers a clear and concise explanation of any proposed change in the rate schedule applicable to the consumer.

(1) When an electric utility proposes a change in a rate schedule, the statement explaining it shall be transmitted to each consumer to which the change applies within thirty (30) days after the utility applies for that change or within sixty (60) days in the case of an electric utility which uses a bimonthly billing system.

Response:

Pursuant to 807 KAR 5:001, Section 16(3) and 807 KAR 5:011, Section 8(5), Kentucky Power Company has complied with this requirement through the notice given pursuant to 807 KAR 5:001, Section 17(2)(b)(3) and 807 KAR 5:011, Section 8(2)(b)(3), respectively.

Filing Requirement
807 KAR 5:051 Section 2(2)

Filing Requirement:

The statement explaining a proposed rate change may be included with the regular bill. (8 Ky.R. 822; eff. 4-7-82.)

Response:

Pursuant to 807 KAR 5:001, Section 16(3) and 807 KAR 5:011, Section 8(5), Kentucky Power Company has complied with this requirement through the notice given pursuant to 807 KAR 5:001, Section 17(2)(b)(3) and 807 KAR 5:011, Section 8(2)(b)(3), respectively.