SALES OF KENTUCKY
JURISDICTIONAL
CUSTOMERS

Filing Requirements
KRS 278.2203 and KRS 278.2205
Cost Allocation Manual

Before

THE PUBLIC SERVICE COMMISSION

OF KENTUCKY

KENTUCKY POWER COMPANY

101A ENTERPRISE DRIVE

FRANKFORT, KENTUCKY 40602

VOLUME 1-A

CASE NO. 2009-00459

AEP AMERICAN ELECTRIC POWER

COST ALLOCATION MANUAL

AS OF June 30, 2009

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 Jeffrey W. Hoersdig/Donald W. Roberts.

Neil W. Felber
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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		51		76	
2	10-22-01	27		52		77	
3	05-10-02	28		53		78	
4	10-18-02	29		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	
18	07/13/09	43		68		93	
19	09/10/09	44		69		94	
20		45		70		95	
21		46		71		96	
22		47		72		97	
23		48		73		98	
24		49		74		99	
25		50		75		100	

AEP 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.

AEP AMERICAN ELECTRIC POWER

Document Number **00-00-01**

Cost Allocation Manual

Section

Controls

Subject

TABLE OF CONTENTS

AEP AMERICAN ELECTRIC POWER

Document Number 00-00-01

Cost Allocation Manual

Section

Controls

Subject

TABLE OF CONTENTS

AMERICAN ELECTRIC POWER

Document Number **00-00-01**

Cost Allocation Manual

Section

Controls

Subject

TABLE OF CONTENTS

AEP AMERICAN ELECTRIC POWER

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.

AEP AMERICAN ELECTRIC POWER

Document Number 00-00-03

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.

A

AMERICAN ELECTRIC POWER

Document Number 00-00-03

Cost Allocation Manual

Section

Controls

Subject

ALPHABETIC SUBJECT INDEX

AEP AMERICAN ELECTRIC POWER

Document Number 00-00-03

Cost Allocation Manual

Section: Controls

Subject: ALPHABETIC SUBJECT INDEX

AEP AMERICAN ELECTRIC POWER

Document Number 00-00-03

Cost Allocation Manual

Section

Controls

Subject

ALPHABETIC SUBJECT INDEX

I (Con't)

J

K

L

M

AEP AMERICAN ELECTRIC POWER

Document Number 00-00-03

Cost Allocation Manual

Section

Controls

Subject

ALPHABETIC SUBJECT INDEX

O

P

AEP AMERICAN ELECTRIC POWER

Document Number **00-00-03**

Cost Allocation Manual

Section

Controls

Subject

ALPHABETIC SUBJECT INDEX

S (Con't)

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 **01-02-02**

Cost Allocation Manual

Section

Organization Chart

Subject

CORPORATE 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.

AEP AND ITS SUBSIDIARIES As of June 30,2009

1	00. American Electric Power Company, Inc. [Note A]
2	01. AEP C&I Company, LLC [Note W]
3	02. AEP Texas Commercial & Industrial Retail GP, LLC [Note W]
4	03. AEP Texas Commercial & Industrial Retail Limited Partnership [Note W]
5	02. AEP Texas Commercial & Industrial Retail Limited Partnership [Note W]
6	02. REP Holdco, LLC [Note W]
7	03. Mutual Energy SWEPCO, LP [Note W]
8	03. REP General Partner LLC [Note W]
9	04. Mutual Energy SWEPCO, LP [Note W]

AEP AMERICAN ELECTRIC POWER

Document Number **01-02-02**

Cost Allocation Manual

Section

Organization Chart

Subject

CORPORATE CHART

AEP AND ITS SUBSIDIARIES As of June 30,2009

10	01. AEP Coal, Inc. [Note L]
11	02. AEP Kentucky Coal, LLC [Note L]
12	02. Snowcap Coal Company, Inc. [Note L]
13	01. AEP Communications, Inc. [Note C]
14	02. AEP Fiber Venture, LLC [Note C]
15	03. AFN, LLC [Note C]
16	01. AEP Credit, Inc. [Note R]
17	01. AEP Generating Company [Note J]
18	01. AEP Investments, Inc. [Note F]
19	02. Amperion [Note DD]
20	02. Intercontinental Exchange Inc. [Note W]
21	02. Microcell Corporation [Note DD]
22	02. Powerspan Corp [Note DD]
23	02. Universal Supercapacitors, LLC [Note DD]
24	01. AEP Nonutility Funding LLC [Note AA]
25	01. AEP Power Marketing, Inc. [Note W]
26	02. AEP Coal Marketing, LLC [Note W]
27	01. AEP Pro Serv, Inc. [Note I]
28	02. Diversified Energy Contractors Company, LLC [Note I]
29	02. United Sciences Testing, Inc. [Note B]
30	01. AEP Resources, Inc. [Note H]
31	02. AEP Delaware Investment Company [Note H]
32	03. AEP Energy Services UK Generation Limited [Note CC]
33	03. AEP Holdings II CV [Note H]
34	04. AEP Energy Services Limited [Note H]
35	02. AEP Delaware Investment Company II [Note H]
36	03. AEP Holdings II CV [Note H]
37	04. AEP Energy Services Limited [Note H]
38	02. AEP Energy Services, Inc. [Note CC]
39	03. AEP Energy Services Gas Holding Company [Note CC]
40	04. AEP Acquisition, LLC [Note CC]
41	04. AEP Energy Services Investments, Inc. [Note CC]
42	02. AEP River Operations LLC [Note Y]
43	03. AEP Elmwood LLC [Note Y]
44	04. Conlease, Inc. [Note Y]
45	04. International Marine Terminals Partnership [Note Y]
46	05. IMT Land Corp [Note Y]
47	01. AEP T&D Services, LLC [Note BB]
48	01. AEP Transmission Holding Company, LLC [Note P]
49	02. AEP Transmission Company, LLC [Note P]
50	02. Electric Transmission America, LLC [Note P]

AEP AMERICAN ELECTRIC POWER

Document Number 01-02-02

Cost Allocation Manual

Section

Organization Chart

Subject

CORPORATE CHART

AEP AND ITS SUBSIDIARIES As of June 30,2009

51	03. Prairie Wind Transmission, LLC [Note P]
52	03. Tallgrass Transmission, LLC [Note P]
53	02. Ohio Series, Potomac-Appalachian Transmission Highline, LLC [Note N]
54	03. PATH Ohio Transmission Company, LLC [Note N]
55	02. Pioneer Transmission, LLC [Note P]
56	02. Potomac-Appalachian Transmission Highline, LLC [Note J]
57	02. West Virginia Series, Potomac-Appalachian Transmission Highline, LLC [Note P]
58	03. PATH West Virginia Transmission Company, LLC [Note P]
59	01. AEP Utilities, Inc. [Note O]
60	02. AEP Texas Central Company [Note J]
61	03. AEP Texas Central Transition Funding II LLC [Note AA]
62	03. AEP Texas Central Transition Funding LLC [Note AA]
63	02. AEP Texas North Company [Note J]
64	03. AEP Texas North Generation Company, LLC [Note E]
65	02. CSW Energy Services, Inc. [Note I]
66	03. Nuvest, L.L.C. [Note U]
67	04. ESG Manufacturing, L.L.C. [Note U]
68	04. ESG, L.L.C. [Note U]
69	04. National Temporary Services, Inc. [Note U]
70	05. Octagon, Inc. [Note U]
71	02. CSW Energy, Inc. [Note S]
72	03. AEP Desert Sky LP II, LLC [Note X]
73	04. Desert Sky Wind Farm LP [Note X]
74	03. AEP Energy Partners, Inc. [Note W]
75	03. AEP Wind Holding, LLC [Note X]
76	04. AEP Properties, LLC [Note X]
77	04. AEP Wind Energy, LLC [Note X]
78	04. AEP Wind GP, LLC [Note X]
79	05. Trent Wind Farm, LP [Note X]
80	04. AEP Wind LP II, LLC [Note X]
81	05. Trent Wind Farm, LP [Note X]
82	02. CSW International, Inc. [Note H]
83	03. CSW UK Finance Company [Note H]
84	02. Electric Transmission Texas, LLC [Note P]
85	01. AEP Utility Funding LLC [Note AA]
86	01. American Electric Power Service Corporation [Note B]
87	02. American Electric Power Foundation [Note FF]
88	01. Appalachian Power Company [Note J]
89	02. Cedar Coal Co. [Note K]
90	02. Central Appalachian Coal Company [Note K]
91	02. Central Coal Company [Note K]

AEP AMERICAN ELECTRIC POWER

Document Number 01-02-02

Cost Allocation Manual

Section

Organization Chart

Subject

CORPORATE CHART

AEP AND ITS SUBSIDIARIES As of June 30,2009

92	02. Southern Appalachian Coal Company [Note K]
93	01. Columbus Southern Power Company [Note J]
94	02. Conesville Coal Preparation Company [Note M]
95	02. Distribution Vision 2010, LLC [Note DD]
96	02. Ohio Valley Electric Corporation [Note E]
97	03. Indiana-Kentucky Electric Corporation [Note E]
98	01. Franklin Real Estate Company [Note T]
99	02. Indiana Franklin Realty, Inc. [Note T]
100	01. Indiana Michigan Power Company [Note J]
101	02. Blackhawk Coal Company [Note K]
102	02. Price River Coal Company [Note K]
103	01. Kentucky Power Company [Note J]
104	01. Kingsport Power Company [Note J]
105	01. Ohio Power Company [Note J]
106	02. Cardinal Operating Company [Note E]
107	02. Central Coal Company [Note K]
108	02. OP Gavin, LLC
109	01. Ohio Valley Electric Corporation [Note E]
110	02. Indiana-Kentucky Electric Corporation [Note E]
111	01. PowerTree Carbon Company, LLC [Note DD]
112	01. Public Service Company of Oklahoma [Note J]
113	01. Southwestern Electric Power Company [Note J]
114	02. Dolet Hills Lignite Company, LLC [Note L]
115	02. SWEPCo Capital Trust I [Note EE]
116	02. Southwest Arkansas Utilities Corporation [Note T]
117	02. The Arklahoma Corporation [Note P]
118	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.

AEP AMERICAN ELECTRIC POWER

Document Number 01-02-02

Cost Allocation Manual

Section

Organization Chart

Subject

CORPORATE CHART

Notes:
K. Coal mining (inactive).
L. Coal 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

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**

AMERICAN ELECTRIC POWER

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

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-02

Cost Allocation Manual

Section

Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

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-

AMERICAN ELECTRIC POWER

Document Number 01-03-02

Cost Allocation Manual

Section

Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

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 intern-ally 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 & Dist Services	Mapping services, project management,

AMERICAN ELECTRIC POWER

Cost Allocation Manual

GROUP/FUNCTION	DESCRIPTION
	design and development of construction projects, drafting and engineering services, contract administration, forestry, and planning services.
Customer Operations	Printing and mailing of customer bills and other required mailings for electric customers, customer information system support, remittance processing, power billing, and credit and collections.
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	Support of system wide budgeting and reporting tools, financial and resource planning, regulatory and rate analysis, tracking and monitoring of construction/capital investments.
Fuel, Emissions and Logistics	Manage fuel procurement and

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-02

Cost Allocation Manual

Section

Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
	related transportation and handling activities.
Generation Business Services	Business support services for operation and maintenance of AEP generating assets.
GBS UST USTI Rata Services	Business support services for AEP generating assets.
Generation	Administration of all generation assets: fossil, hydro, and engineering technical & environmental services.
Generation-Fossil & Hydro	Administration of all fossil and hydro production and support groups such as regional administration, budgeting, fossil operator training, purchasing, etc.
Engineering Project Field Services	Support engineering, technical and environmental services for the operation of AEP generating assets.
Information Technology	Information processing, business unit support, application development, client computing and technical software support and EAS solutions and

AMERICAN ELECTRIC POWER

Document Number 01-03-02

Cost Allocation Manual

Section

Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
	telecommunication operations.
Legal	Legal counsel and public/regulatory policy for questions, issues, cases, etc. for all aspects of the AEP System.
Nuclear Generation	Administration of all nuclear generation assets.
Regulatory Services	Support of system wide regulatory and rate analysis.
Risk	Coordination of risk assessment, credit risk management and insurance coverage.
Shared Services	Administer and coordinate business logistics, human resources, and information technology.
Transmission	Project management, design and development of construction projects, drafting and engineering services, contract administration, development of standards related to electric transmission systems, forestry management, and impact studies.
Treasury	Cash management, financing, and investment services.
AEP - Utility	Distribution

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-02

Cost Allocation Manual

Section

Affiliate Transactions

Subject

SERVICES RENDERED BY AEPSC

GROUP/FUNCTION	DESCRIPTION
Operations	operations, customer and regulatory relationships.
Utility Operations East	Distribution operations, customer and regulatory relationships.
AEP Utilities - West	Distribution operations, customer and regulatory relationships.

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-03

Cost Allocation Manual

Section

Affiliate Transactions

Subject

Intercompany Products and Services

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.

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-03

Cost Allocation Manual

Section

Affiliate Transactions

Subject

Intercompany Products and Services

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.

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:

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-03

Cost Allocation Manual

Section

Affiliate Transactions

Subject

Intercompany Products and Services

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.

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

AEP AMERICAN ELECTRIC POWER

CATEGORY	*DESCRIPTION*
	1300 MW units.
Building Space and Office Services	Billing of rent and carrying charge for building space occupied.
Water Transportation, Coal and Consumables Handling, and Gypsum	Provide barging and services at transfer 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.

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-03

Cost Allocation Manual

Section

Affiliate Transactions

Subject

Intercompany Products and Services

CATEGORY	DESCRIPTION
EHV Transmission System	Sharing of costs incurred regarding the ownership, operation and maintenance of AEP's extra-high voltage (EHV) trans-mission system.
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.
Coal Preparation	Provide coal washing and handling services.
Hydro Plant	Provide supervision,

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-03

Cost Allocation Manual

Section

Affiliate Transactions

Subject

Intercompany Products and Services

CATEGORY	DESCRIPTION
	maintenance and operation of hydro plant and associated facilities.
Joint Facilities	Share costs of operations and maintenance of jointly owned facilities (primarily generating 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 Trona.

AMERICAN ELECTRIC POWER

Document Number **01-03-04**

Cost Allocation Manual

Section

Affiliate Transactions

Subject

MONEY POOL

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 the orders that have been 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.

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-04

Cost Allocation Manual

Section

Affiliate Transactions

Subject

MONEY POOL

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.

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.

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-05

Cost Allocation Manual

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 attribution bases (see the Appendix to this manual for a complete list of approved attribution bases).

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 attribution basis 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

The cost of fringe benefits such as pension expense is loaded on to labor dollars.

AEP AMERICAN ELECTRIC POWER

Document Number 01-03-05

Cost Allocation Manual

Section

Affiliate Transactions

Subject

RESEARCH AND DEVELOPMENT

PROCEDURE (Cont'd)

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. A&G overheads include costs classified to the following accounts:

920.0	A&G salaries
921.0	Office supplies and expenses
923.0	Outside services employed
930.2	Miscellaneous general expenses

The overhead expenses included in these accounts are loaded separately by account to each R&D project. Each individual loading is credited to the applicable A&G account.

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.

AEP AMERICAN ELECTRIC POWER

Document Number **01-03-06**

Cost Allocation Manual

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.

AEP AMERICAN ELECTRIC POWER

Document Number **01-03-06**

Cost Allocation Manual

Section

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.

AMERICAN ELECTRIC POWER

Document Number 01-03-07

Cost Allocation Manual

Section

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.

AMERICAN ELECTRIC POWER

Document Number 01-03-08

Cost Allocation Manual

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.

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.

AEP AMERICAN ELECTRIC POWER

Document Number **02-01-01**

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.

AEP AMERICAN ELECTRIC POWER

Document Number **02-02-01**

Cost Allocation Manual

Section

Corporate

Subject

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-01

Cost Allocation Manual

Section

Corporate

Subject

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.

02-02-05

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-02

Cost Allocation Manual

Section

Corporate

Subject

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.

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-02

Cost Allocation Manual

Section

Corporate

Subject

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).

AMERICAN ELECTRIC POWER

Document Number 02-02-02

Cost Allocation Manual

Section

Corporate

Subject

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.

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-03

Cost Allocation Manual

Section

Corporate

Subject

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-

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-03

Cost Allocation Manual

Section

Corporate

Subject

THE COST ALLOCATION PROCESS

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.

AEP AMERICAN ELECTRIC POWER

Document Number **02-02-04**

Cost Allocation Manual

Section

Corporate

Subject

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-

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-04

Cost Allocation Manual

Section

Corporate

Subject

COST POOLING AND COST ASSIGNMENT

productive pay)
- building costs
- computer 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 square footage, labor dollars, and total cost input.

AMERICAN ELECTRIC POWER

Document Number 02-02-05

Cost Allocation Manual

Section

Corporate

Subject

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 Attribution Bases used for Service Company billings.

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-05

Cost Allocation Manual

Section
Corporate

Subject
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

AMERICAN ELECTRIC POWER

Document Number 02-02-05

Cost Allocation Manual

Section

Corporate

Subject

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

AEP AMERICAN ELECTRIC POWER

Document Number **02-02-05**

Cost Allocation Manual

Section

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-05

Cost Allocation Manual

Section

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

AEP AMERICAN ELECTRIC POWER

Document Number **02-02-05**

Cost Allocation Manual

Section

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-02-05

Cost Allocation Manual

Section

Corporate

Subject

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-03-01

Cost Allocation Manual

Section

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.

02-03-02

AMERICAN ELECTRIC POWER

Document Number 02-03-02

Cost Allocation Manual

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.

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-01

Cost Allocation Manual

Section

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.

02-04-12

AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section
State Commission Rules

Subject
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 REQUIRE-MENTS

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 books and records separately form 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

AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section
State Commission Rules

Subject
ARKANSAS RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

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

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.

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 affiliate 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 creation and use of

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

SUBJECT	REQUIREMENTS
	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 debet 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 utility of financial

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

SUBJECT	REQUIREMENTS
	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 andy 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 documentation, and the

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

SUBJECT	REQUIREMENTS
	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 the utility and applied

AEP AMERICAN ELECTRIC POWER

Document Number **02-04-02**

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

SUBJECT	REQUIREMENTS
	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 files with the Commssion an

SUBJECT	REQUIREMENTS
	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 the public utility is out of

Cost Allocation Manual

SUBJECT	REQUIREMENT
	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.

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-02

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

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 Bal 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 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 utility that the public

AEP AMERICAN ELECTRIC POWER

Document Number **02-04-02**

Cost Allocation Manual

Section

State Commission Rules

Subject

ARKANSAS RULES AND REQUIREMENTS

	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.

AEP AMERICAN ELECTRIC POWER

Document Number **02-04-03**

Cost Allocation Manual

Section

State Commission Rules

Subject

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-03

Cost Allocation Manual

Section

State Commission Rules

Subject

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,

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-03

Cost Allocation Manual

Section

State Commission Rules

Subject

INDIANA RULES AND REQUIREMENTS

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*

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-03

Cost Allocation Manual

Section

State Commission Rules

Subject

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;
Guiding	provided, however, that

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-03

Cost Allocation Manual

Section

State Commission Rules

Subject

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

OTHER REQUIREMENTS (Cont'd)

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.

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-04

Cost Allocation Manual

Section

State Commission Rules

Subject

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

AMERICAN ELECTRIC POWER

Document Number 02-04-04

Cost Allocation Manual

Section

State Commission Rules

Subject

KENTUCKY RULES AND REQUIREMENTS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-04

Cost Allocation Manual

Section

State Commission Rules

Subject

KENTUCKY RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-04

Cost Allocation Manual

Section

State Commission Rules

Subject

KENTUCKY RULES AND REQUIREMENTS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-04

Cost Allocation Manual

Section

State Commission Rules

Subject

KENTUCKY RULES AND REQUIREMENTS

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)]*

Cost Allocation Manual

Section

State Commission Rules

Subject

KENTUCKY RULES AND REQUIREMENTS

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,

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-04

Cost Allocation Manual

Section

State Commission Rules

Subject

KENTUCKY RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-04

Cost Allocation Manual

Section

State Commission Rules

Subject

KENTUCKY RULES AND REQUIREMENTS

SUBJECT	*REQUIREMENT*
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

AMERICAN ELECTRIC POWER

Cost Allocation Manual

SUBJECT	*REQUIREMENT*
	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.

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-05

Cost Allocation Manual

Section

State Commission Rules

Subject

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]

AMERICAN ELECTRIC POWER

Document Number 02-04-05

Cost Allocation Manual

Section

State Commission Rules

Subject

LOUISIANA RULES AND REQUIREMENTS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-05

Cost Allocation Manual

Section

State Commission Rules

Subject

LOUISIANA RULES AND REQUIREMENTS

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

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),

AMERICAN ELECTRIC POWER

Cost Allocation Manual

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

AEP AMERICAN ELECTRIC POWER

Cost Allocation Manual

Section

State Commission Rules

Subject

LOUISIANA RULES AND REQUIREMENTS

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]

AMERICAN ELECTRIC POWER

Document Number 02-04-05

Cost Allocation Manual

Section

State Commission Rules

Subject

LOUISIANA RULES AND REQUIREMENTS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-05

Cost Allocation Manual

Section

State Commission Rules

Subject

LOUISIANA RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

SUJECT	REQUIREMENT
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 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 transactions must be maintained until the Company's next

AMERICAN ELECTRIC POWER

Cost Allocation Manual

SUBJECT	*REQUIREMENT*
(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 Mandating of Retail Access	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

SUBJECT	***REQUIREMENT***
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]

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-06

Cost Allocation Manual

Section

State Commission Rules

Subject

MICHIGAN RULES AND REQUIREMENTS

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.]

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-06

Cost Allocation Manual

Section

State Commission Rules

Subject

MICHIGAN RULES AND REQUIREMENTS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-06

Cost Allocation Manual

Section
State Commission Rules

Subject
MICHIGAN RULES AND REQUIREMENTS

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	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
Guiding Principles	

AMERICAN ELECTRIC POWER

Document Number 02-04-06

Cost Allocation Manual

Section

State Commission Rules

Subject

MICHIGAN RULES AND REQUIREMENTS

SUBJECT	***REQUIREMENT***
(Cont'd)	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,
Guiding Principles	consistent with these cross-subsidization

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-06

Cost Allocation Manual

Section

State Commission Rules

Subject

MICHIGAN RULES AND REQUIREMENTS

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	

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-06

Cost Allocation Manual

Section

State Commission Rules

Subject

MICHIGAN RULES AND REQUIREMENTS

SUBJECT	*REQUIREMENT*
(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

AMERICAN ELECTRIC POWER

SUBJECT	*REQUIREMENT*
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

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.

AMERICAN ELECTRIC POWER

Document Number 02-04-07

Cost Allocation Manual

Section

State Commission Rules

Subject

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	The CAM will include: (1) An organization chart of the holding company, depicting all affiliates, as well as a description of activities in which

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-07

Cost Allocation Manual

Section

State Commission Rules

Subject

OHIO RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

Cost Allocation Manual

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 many 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.

AMERICAN ELECTRIC POWER

Document Number 02-04-08

Cost Allocation Manual

Section

State Commission Rules

Subject

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.

AMERICAN ELECTRIC POWER

Document Number 02-04-08

Cost Allocation Manual

Section

State Commission Rules

Subject

OKLAHOMA RULES AND REGULATIONS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-08

Cost Allocation Manual

Section

State Commission Rules

Subject

OKLAHOMA RULES AND REGULATIONS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-08

Cost Allocation Manual

Section

State Commission Rules

Subject

OKLAHOMA RULES AND REGULATIONS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-08

Cost Allocation Manual

Section

State Commission Rules

Subject

OKLAHOMA RULES AND REGULATIONS

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

AMERICAN ELECTRIC POWER

Cost Allocation Manual

Section

State Commission Rules

Subject

OKLAHOMA RULES AND REGULATIONS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-08

Cost Allocation Manual

Section

State Commission Rules

Subject

OKLAHOMA RULES AND REGULATIONS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-08

Cost Allocation Manual

Section

State Commission Rules

Subject

OKLAHOMA RULES AND REGULATIONS

SUBJECT	REQUIREMENTS
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

AMERICAN ELECTRIC POWER

Document Number 02-04-08

Cost Allocation Manual

Section

State Commission Rules

Subject

OKLAHOMA RULES AND REGULATIONS

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

Cost Allocation Manual

SUBJECT	REQUIREMENTS
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]

AMERICAN ELECTRIC POWER

Document Number **02-04-09**

Cost Allocation Manual

Section

State Commission Rules

Subject

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.

AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

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)]

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

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,

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

SUBJECT	REQUIREMENT
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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

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,

AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

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	REQUIUREMENT
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

AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

SUBJECT	REQUIUREMENT
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)]

AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

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)]

AMERICAN ELECTRIC POWER

Document Number 02-04-10

Cost Allocation Manual

Section

State Commission Rules

Subject

TEXAS RULES AND REQUIREMENTS

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)]

AMERICAN ELECTRIC POWER

Document Number 02-04-11

Cost Allocation Manual

Section

State Commission Rules

Subject

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

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 cha[ter, 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-

AMERICAN ELECTRIC POWER

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-11

Cost Allocation Manual

Section

State Commission Rules

Subject

VIRGINIA RULES AND REQUIREMENTS

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-Tarriffed 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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-11

Cost Allocation Manual

Section

State Commission Rules

Subject

VIRGINIA RULES AND REQUIREMENTS

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

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-11

Cost Allocation Manual

Section

State Commission Rules

Subject

VIRGINIA RULES AND REQUIREMENTS

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.

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-11

Cost Allocation Manual

Section

State Commission Rules

Subject

VIRGINIA RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-11

Cost Allocation Manual

Section

State Commission Rules

Subject

VIRGINIA RULES AND REQUIREMENTS

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

AMERICAN ELECTRIC POWER

Document Number 02-04-11

Cost Allocation Manual

Section

State Commission Rules

Subject

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]*

AEP AMERICAN ELECTRIC POWER

Document Number 02-04-12

Cost Allocation Manual

Section

State Commission Rules

Subject

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.

AEP AMERICAN ELECTRIC POWER

Document Number **03-01-01**

Cost Allocation Manual

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.

AEP AMERICAN ELECTRIC POWER

Document Number 03-01-01

Cost Allocation Manual

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.

AEP AMERICAN ELECTRIC POWER

Document Number **03-02-01**

Cost Allocation Manual

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.
	03-02-02
CODING BLOCKS	Various coding blocks, also known as chartfields, are used to code financial transactions for accounting and cost allocation purposes.
	03-02-03

AEP AMERICAN ELECTRIC POWER

Document Number 03-02-02

Cost Allocation Manual

Section

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 General and Corporate 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.

AEP AMERICAN ELECTRIC POWER

Document Number 03-02-03

Cost Allocation Manual

Section

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.

AEP AMERICAN ELECTRIC POWER

Document Number **03-02-03**

Cost Allocation Manual

Section

Transactions

Subject

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.

AEP AMERICAN ELECTRIC POWER

Document Number 03-02-03

Cost Allocation Manual

Section

Transactions

Subject

CHARTFIELDS

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.

AEP AMERICAN ELECTRIC POWER

Document Number **03-03-01**

Cost Allocation Manual

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.
	03-03-03

AEP AMERICAN ELECTRIC POWER

Document Number 03-03-02

Cost Allocation Manual

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

AEP AMERICAN ELECTRIC POWER

Document Number 03-03-02

Cost Allocation Manual

Section

Time Reporting

Subject

TIME RECORDS

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.

AEP AMERICAN ELECTRIC POWER

Document Number 03-03-03

Cost Allocation Manual

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)

AMERICAN ELECTRIC POWER

Document Number 03-03-03

Cost Allocation Manual

Section

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.

AEP AMERICAN ELECTRIC POWER

Document Number **03-04-01**

Cost Allocation Manual

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 attribution bases (i.e., allocation factors) approved by the SEC under PUHCA 1935 and continued after repeal of PUHCA. **03-04-04**
REPORTS	AEPSC prepares a monthly billing report for all billed costs. **03-04-05**

AEP AMERICAN ELECTRIC POWER

Document Number **03-04-02**

Cost Allocation Manual

Section

AEPSC Billing System

Subject

SYSTEM OF INTERNAL CONTROLS

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.

AMERICAN ELECTRIC POWER

Document Number 03-04-02

Cost Allocation Manual

Section

AEPSC Billing System

Subject

SYSTEM OF INTERNAL CONTROLS

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

AMERICAN ELECTRIC POWER

Document Number 03-04-02

Cost Allocation Manual

Section

AEPSC Billing System

Subject

SYSTEM OF INTERNAL CONTROLS

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

AEP AMERICAN ELECTRIC POWER

Document Number 03-04-02

Cost Allocation Manual

Section

AEPSC Billing System

Subject

SYSTEM OF INTERNAL CONTROLS

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 attribution bases 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, and Indiana requires an affiliate transactions audit every two 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.

AEP AMERICAN ELECTRIC POWER

Document Number 03-04-03

Cost Allocation Manual

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 SERVICE IDs

A billable Service ID 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 Service IDs (billable and non-billable):

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

FUNCTION AND TYPES OF SERVICE Ids (Cont'd)

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

Allocated - An Allocated Service ID is used when the service being performed benefits two or more companies or company segments. The monthly cost accumulated for an Allocated Service ID 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 attribution bases (i.e., allocation factors) to allocate costs that are accumulated under Allocated Service IDs.

SCFringe - The SCFringe Service ID 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 Service ID is used to accumulate certain overhead costs applicable to each department. This Service ID 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). 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 Service ID 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.

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

The ABM Activity Request 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

Line Item	Information
	process to which the 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 attribution basis 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

The work order request form requires the following information:

Line Item	Information
Recommended Title	The requesting business unit provides the recommended 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.

AEP AMERICAN ELECTRIC POWER

Document Number 03-04-03

Cost Allocation Manual

Section
AEPSC Billing System

Subject
Work Order Accounting

Line Item	Information
Work Order Type	The requesting business unit provides the Work 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.

Cost Allocation Manual

Line Item	Information
Recommended Attribution Basis	The requesting business unit supplies the recommended attribution basis code for the work order. The attribution basis code identifies the proposed method of allocation for Allocated work orders. The attribution basis becomes an attribute of the work order. Work orders that pertain to a single company should be assigned an attribution basis 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.

AMERICAN ELECTRIC POWER	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: -

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:

AMERICAN ELECTRIC POWER

Document Number 03-04-04

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 Attribution Basis code that, along with the Benefiting Location code, ultimately determines the dollars of cost that will be charged to each client company. Attribution Basis codes are assigned according to the nature of the services performed.

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

FUNCTION OF THE ATTRIBUTION BASIS CODE

The Attribution Basis 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 Attribution Basis 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 attribution basis are accurate and kept up to date. The values are refreshed according to the intervals determined for each attribution basis (e.g., monthly, quarterly, semi-annually and annually).

The attribution basis 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 Attribution Basis code. Requestors are in

AEP AMERICAN ELECTRIC POWER

Document Number 03-04-04

Cost Allocation Manual

Section

AEPSC Billing System

Subject

BILLING ALLOCATIONS

the best position to recommend an appropriate Attribution Basis code since they are intimately familiar with the work to be performed and with the inherent cost drivers. Corporate Accounting reviews all Attribution Basis code selections for reasonableness.

EXAMPLES

Examples of the appropriate use of attribution bases are captured in the following table:

Activity/Shared Service	Attribution Basis
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 ATTRIBUTION BASES

The APPENDIX to this manual contains a list of all the approved attribution bases.

AMERICAN ELECTRIC POWER

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 monthly bill for services rendered by AEPSC includes the following elements for each client Company:

SEGMENT	***ELEMENT***
Report Header	• Client Company Number • Client Name • Period Covered • Fiscal Year
For Activities (i.e. "G" Work Orders)	• Project Costing Business Unit • Project ID • G Work Order • Department Group • Department Group Description • Salary Amount • Salary Related Amount • Outside Services Amount • Travel/Employee Expense Amount • Overheads Amount • Other Amount • Total Work Order Amount
For Work Orders (i.e., Non "G" Work Orders)	• Project Costing Business Unit • Project ID • Work Order Number • Department Group

AEP AMERICAN ELECTRIC POWER

Document Number 03-04-05

Cost Allocation Manual

Section

AEPSC Billing System

Subject

REPORTS

SEGMENT	*ELEMENT*
For Work Orders (i.e., Non "G" Work Orders) (Cont'd)	• Department Group Description • Salary Amount • Salary Related Amount • Outside Services Amount • Travel/Employee Expense Amount • Overheads Amount • Other Amount • Total Work Order Amount
End of Report	• Total Salary Amount • Total Salary Related Amount • Total Outside Services Amount • Total Travel/Employee Expense Amount • Total Computer Expense Amount • Total Other Amount • Total Overheads Amount • Total Client Company Amount

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.

AMERICAN ELECTRIC POWER

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

AMERICAN ELECTRIC POWER

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 (as in the case of Ohio Power and Columbus Southern Power) 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:

AMERICAN ELECTRIC POWER

Document Number 03-05-02

Cost Allocation Manual

Section

Intercompany Billing

Subject

BILLING SYSTEM

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 attribution basis of transmission pole miles. This intercompany billing establishes an accounts receivable entry for the performing company

AMERICAN ELECTRIC POWER

and a corresponding accounts payable entry for the four remaining benefiting companies.

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 attribution bases for service company billings. The attribution basis 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 attribution basis 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.

AMERICAN ELECTRIC POWER

Document Number 03-05-02

Cost Allocation Manual

Section

Intercompany Billing

Subject

BILLING SYSTEM

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.

AMERICAN ELECTRIC POWER

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

AEP AMERICAN ELECTRIC POWER

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:

AMERICAN ELECTRIC POWER

Document Number 03-06-02

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.

AMERICAN ELECTRIC POWER

Document Number 03-06-02

Cost Allocation Manual

Section

InterUnit Accounting

Subject

JOINT PAYMENTS AND JOURNAL TRANSACTIONS

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 attribution bases for service company billings. The attribution basis 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.

AEP 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

AMERICAN ELECTRIC POWER

Document Number 03-07-02

Cost Allocation Manual

Section

Asset Transfers

Subject

PLANT AND EQUIPMENT

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 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.

The AEP Legal Department is to be informed of any proposed sale that in the aggregate exceeds $50,000 (or as otherwise required by regulation) for the purpose of determining whether there are any mortgage restrictions or whether any regulatory approvals must be sought.

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, taxes, and administrative and general expenses.

AEP AMERICAN ELECTRIC POWER

Document Number 03-07-03

Cost Allocation Manual

Section

Asset Transfers

Subject

MATERIALS AND SUPPLIES

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.

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

AEP 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**

AMERICAN ELECTRIC POWER

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

AEP AMERICAN ELECTRIC POWER

Document Number 04-02-02

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
SERVICE AGREEMENTS

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.

AFFILIATED TRANSACTIONS AGREEMENT

The Affiliated Transactions Agreement, dated December 31, 1996, is among Appalachian Power Company, Columbus Southern Power Company, 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.

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

AMERICAN ELECTRIC POWER

Document Number 04-02-02

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
SERVICE AGREEMENTS

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, 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, 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, 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, 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, construction, 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, 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, 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.

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 PURCHASE AGREEMENT (ACCOUNTS RECEIVABLE)	This agreement, dated 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 AGENCY AGREEMENT (ACCOUNTS RECEIVABLE	This agreement, dated January 30, 2008, is among AEP Credit, Inc. and certain AEP 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	This agreement, dated December 22, 1997, is between West Texas Utilities, Inc. and

AEP AMERICAN ELECTRIC POWER

Document Number 04-02-02

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
SERVICE AGREEMENTS

SERVICE COMPANY AGENCY AGREEMENT

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.

SOUTH TEXAS PROJECT OPERATING AGREEMENT

This agreement, dated November 17, 1997, is among the City of San Antonio (acting through the City Public Service Board of San Antonio), Central Power and Light Company, Houston Lighting and Power Company (now Reliant Energy, HLP), the City of Austin and the operator of the South Texas Project, STP Nuclear Operating Company (Opco).

This operating agreement sets forth the rights and obligations between the noted participants. It also explains the responsibilities of Opco for licensing, operation, maintenance, modification, decontamination and decommissioning of the South Texas Project.

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.

AMERICAN ELECTRIC POWER

Document Number 04-02-03

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject

MINING AND TRANSPORTATION

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 PREPARATION

Under the coal preparation contract between Columbus Southern Power Company and Conesville Coal Preparation Company, dated November 5, 1984, as amended on August 1, 1986 and January 1, 1987, Conesville Coal

Preparation Company washes, beneficiates and handles the coal of Columbus Southern Power Company.

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

AMERICAN ELECTRIC POWER

Document Number 04-02-03

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
MINING AND TRANSPORTATION

1, 1986, is among Appalachian Power Company, Ohio Power Company and AEP Generating 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.

Appendix A to the above agreement, dated March 1, 1978, concerns charges and credits to promote the efficient use of barges to minimize barge delay. These are in the form of barge demurrage charges and towboat charges.

COAL TRANSFER-PUTNAM COAL TERMINAL

The Coal Transfer Agreement - Putnam Coal Terminal, dated September 15, 1980, is between Appalachian Power Company (Operator) and Ohio Power Company (User).

This agreement provides for the Operator to unload coal for the User from unit trains, transfer such coal from the unloading point at the terminal to a loading point on the Kanawha River, re-load such coal in barges, and temporarily store such coal as required prior to transport by water.

COAL TRANSFER-COOK COAL TERMINAL

The Coal Transfer Agreement - Cook Coal Terminal, dated June 17, 1983, is between Ohio Power Company (Operator) and Indiana Michigan Power Company (User).

This agreement provides for the Operator to unload coal for the User 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 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.

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 April 1, 1982, is among Ohio Power Company, Appalachian Power Company, and Indiana Michigan Power Company.

This agreement provides for Ohio Power Company to furnish routine, preventive and other maintenance to the railroad hopper cars it leases and furnish similar services to the hopper cars Appalachian Power Company and Indiana Michigan Power lease.

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

AMERICAN ELECTRIC POWER

Document Number 04-02-03

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
MINING AND TRANSPORTATION

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	Columbus Southern Power Company and AEP Pro Serv, Inc.
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.
09-27-1996	Columbus Southern Power 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.

AMERICAN ELECTRIC POWER

Document Number **04-02-05**

Cost Allocation Manual

Section
Affiliated Contracts with Regulated Companies

Subject
JOINT OPERATING AGREEMENTS

SUMMARY

The Philip Sporn Plant, Amos Plant Unit No 3 and certain other AEP facilities are jointly owned and operated. The Racine Hydro Project is owned by Ohio Power Company and operated by Appalachian Power Company.

PHILIP SPORN PLANT AGREEMENT

The Philip Sporn Plant Agreement, dated January 1, 1998, is between Appalachian Power Company and Ohio Power Company ("Owners").

Appalachian Power Company owns two 150,000 kilowatt generating units (Sporn units Nos. 1 and 3) and Ohio Power Company owns two 150,000 kilowatt generating units and one 450,000 kilowatt generating unit (Sporn units 2,4,and 5). The Owners desire that Appalachian Power Company operate and maintain Philip Sporn Plant.

AMOS UNIT NO. 3 OPERATING AGREEMENT

The Amos Unit No. 3 Operating Agreement, dated July 26, 1973, is between Appalachian Power Company and Ohio Power Company.

Appalachian Power Company and Ohio Power Company are joint owners of a 1,300,000 kilowatt steam electric generating unit known as Unit 3 at the John Amos Plant. Appalachian Power Company operates and maintains Amos Unit No. 3 for both itself and Ohio Power Company.

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

AMERICAN ELECTRIC POWER

Document Number 04-02-05

Cost Allocation Manual

Section
Affiliated Contracts with Regulated Companies

Subject
JOINT OPERATING AGREEMENTS

EAST HVDC INTERCONNECTION AGREEMENT (Cont'd)	SWEPCO operates the facility. It owns certain of the alternating current facilities and charges the other participants 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.
RACINE HYDRO PROJECT OPERATING AGREEMENT	The Racine Hydro Project Operating Agreement, dated June 1, 1978, is between Appalachian Power Company and Ohio Power Company. This agreement provides that Ohio Power Company owns a hydroelectric plant located on the Ohio River near Racine, Ohio. Appalachian Power operates and maintains this plant for Ohio Power in accordance with the provisions set forth in the agreement.

AEP 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.

AMERICAN ELECTRIC POWER

Document Number **04-02-07**

Cost Allocation Manual

Section
Affiliate Contracts with Regulated Companies

Subject
AEP SYSTEM AMENDED AND RESTATED MONEY POOL AGREEMENT

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 December 9, 2004,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).

AEP AMERICAN ELECTRIC POWER

Document Number 04-02-08

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 December 1, 2006, 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).

AEP AMERICAN ELECTRIC POWER

Document Number **04-03-01**

Cost Allocation Manual

Section

Databases

Subject

OVERVIEW

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	A database file contains copies of all agreements between AEP regulated utilities and their affiliates.
	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

AEP AMERICAN ELECTRIC POWER

Cost Allocation Manual

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

AEP 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.

AEP 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

AMERICAN ELECTRIC POWER

Cost Allocation Manual

TRANSFERRED EMPLOYEES (Cont'd)	customers, are incorporated in this manual by reference.

04-04-03

AEP AMERICAN ELECTRIC POWER

Document Number 04-04-02

Cost Allocation Manual

Section

Job Descriptions

Subject

SHARED EMPLOYEES (PUCO)

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 (Case No. 99-1729-EL-ETP) and Ohio Power Company (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.]

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.]

AMERICAN ELECTRIC POWER

Document Number **04-05-01**

Cost Allocation Manual

Section

Complaint Log

Subject

OVERVIEW

SUMMARY	The corporate separation rules adopted by the Public Utilities Commission of Ohio require Columbus Southern Power Company and Ohio Power Company 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

AMERICAN ELECTRIC POWER

Document Number **04-05-02**

Cost Allocation Manual

Section

Complaint Log

Subject

CORPORATE SEPARATION (PUCO)

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 General Counsel, or the General Counsel's designee in Ethics & Compliance, 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 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.

AMERICAN ELECTRIC POWER

Document Number **04-06-01**

Cost Allocation Manual

Section

Board of Directors Minutes

Subject

OVERVIEW

SUMMARY	The corporate separation rules adopted by the Public Utilities Commission of Ohio (PUCO) require Columbus Southern Power Company and Ohio Power Company, 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

AEP AMERICAN ELECTRIC POWER

Document Number **04-06-02**

Cost Allocation Manual

Section

Board of Directors Minutes

Subject

COPIES (PUCO)

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 and Ohio Power Company
CAM REQUIREMENTS	The required minutes are incorporated in this manual by reference and, as such, are part of this manual.

AMERICAN ELECTRIC POWER

Document Number **99-00-01**

Cost Allocation Manual

Section: 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 ATTRIBUTION BASES	An attribution basis 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 attribution bases is maintained as part of this manual.
	99-00-04
LIST OF PRIMARY ATTRIBUTION BASES BY FUNCTION	Attribution bases are assigned to final cost objectives generally based on the nature (i.e., function) of the work performed. A list of the primary attribution bases 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

Cost Allocation Manual

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

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-02

Cost Allocation Manual

Section

Appendix

Subject

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

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-02

Cost Allocation Manual

Section

Appendix

Subject

GLOSSARY OF KEY TERMS

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).

AMERICAN ELECTRIC POWER

Document Number 99-00-03

Cost Allocation Manual

Section

Appendix

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

AMERICAN ELECTRIC POWER

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)].

TEXAS (Cont'd)

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 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.

AMERICAN ELECTRIC POWER

Document Number 99-00-04

Cost Allocation Manual

Section

Appendix

Subject

LIST OF APPROVED ATTRIBUTION BASES

SUMMARY

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

NO.	*ATTRIBUTION BASES*	*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

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-04**

Cost Allocation Manual

Section

Appendix

Subject

LIST OF APPROVED ATTRIBUTION BASES

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

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-04

Cost Allocation Manual

Section

Appendix

Subject

LIST OF APPROVED ATTRIBUTION BASES

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

AMERICAN ELECTRIC POWER

Document Number 99-00-04

Cost Allocation Manual

Section

Appendix

Subject

LIST OF APPROVED ATTRIBUTION BASES

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 Twelve Months Total of the Same for All Companies	Semi-Annually

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-04

Cost Allocation Manual

Section

Appendix

Subject

LIST OF APPROVED ATTRIBUTION BASES

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

AMERICAN ELECTRIC POWER

Document Number **99-00-04**

Cost Allocation Manual

Section

Appendix

Subject

LIST OF APPROVED ATTRIBUTION BASES

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

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-04

Cost Allocation Manual

Section

Appendix

Subject

LIST OF APPROVED ATTRIBUTION BASES

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

AMERICAN ELECTRIC POWER

Document Number 99-00-05

Cost Allocation Manual

Section

Appendix

Subject

LIST OF PRIMARY ATTRIBUTION BASES BY FUNCTION

SUMMARY

The following table identifies the primary attribution bases that are associated with the listed functions.

GROUP/FUNCTION	*PRIMARY ATTRIBUTION BASES*
Audit Services	Total Assets, 100% to One Company, Number of Employees
Business Logistics	100% to One Company, Number of Purchase Orders, Number of Stores Transactions
Chairman	Total Assets, 100% to One Company, Number of Employees
Commercial Operations	100% to One Company, Total Assets, Number of Electric Retail Customers
Corporate Accounting	100% to One Company, Total Assets, Number of GL Transactions
Corporate Communications	Number of Employees, Total Assets, Number of Electric Retail Customers
Corporate Human Resources	Number of Employees, AEPSC Bill less Indir and Int, AEPSC Past 3 Months Total Bill
Corporate Planning and Budgeting	Total Assets, Total Fixed Assets, Number of Electric Retail Customers
Customer & Dist Services	Number of Electric Retail Customers, 100% to One Company, Total Fixed Assets
Customer Operations	100% to One Company, Number of Electric Retail Customers, Number of CIS Customers Mail
Environment and Safety	100% to One Company, MW Generating Capability, Number of Employees
Federal Affairs	Number of Employees, AEPSC Past 3 Months Total Bill, 100% to One Company, Total Assets, AEPSC Bill less Indir and Int, Payroll - AEPSC less Indir & Int
Finance, Acct and Strategic Plng	Total Assets, Number of Employees, 100% to One Company
Fuel, Emissions & Logistics	Tons of Fuel Acquired, 100% to One Company, MW Generating Capability
Generation Business Services	MW Generating Capability, Level of Construction-Production, 100% to One Company
GBS UST USTI Rata Services	100% to One Company, Payroll - MW

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-05

Cost Allocation Manual

Section

Appendix

Subject

LIST OF PRIMARY ATTRIBUTION BASES BY FUNCTION

GROUP/FUNCTION	*PRIMARY ATTRIBUTION BASES*
	Generating Capacity, AEPSC Past 3 Months Total Bill
Generation	MW Generating Capability, Level of Construction-Production, Number of Stores Transactions
Generation-Fossil & Hydro	100% to One Company, MW Generating Capability, Total Assets
Engineering Project & Field Services	100% to One Company, Level of Construction-Production, MW Generating Capability
Information Technology	Total Assets, Number of Electric Retail Customers, MW Generating Capability
Investor Relations	Total Assets, 100% to One Company, Number of Employees
Legal GC/Administration	100% to One Company, Total Assets, Number of Employees
Nuclear	100% to One Company, AEPSC Past 3 Months Total Bill, MW Generating Capability
Policy, Finance and Strategic Planning	Total Assets, 100% to One Company, Total Fixed Assets
Regulatory Services	Total Assets, Number of Trans Pole Miles, 100% to One Company
Risk	Total Fixed Assets, AEPSC Past 3 Months Total Bill, 100% to One Company
Shared Services	Total Assets, AEPSC Bill less Indirect and Interest, 100% to One Company
Transmission	100% to One Company, Level of Construction-Transmission, Number of Transmission Pole Miles
Treasury	Total Assets, AEPSC Past 3 Months Total Bill, 100% to One Company
Utility Operations	Total Assets, Number of Employees, Number of Phone Center Calls
Utilities - East	Total Assets, 100% to One Company, Number of Employees
Utilities - West	Total Assets, 100% to One Company, Total Fixed Assets

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY 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	07/01/93	Rail Car Lease Agreement(West)
Central	07/29/97	Rail Car Maintenance Facility Agreement
Company	10/29/99	(West)
(Formerly	06/16/00	Transmission Coordination Agreement (West)
Central		Amended and Restated Purchase Agreement
Power and		Between CSW Credit, Inc. and Affiliate (West)
Light)	06/16/00	Companies
		Amended and Restated Agency Agreement Between
		CSW Credit, Inc. and Affiliate (West)
	06/01/99	Companies
	03/30/99	CSW System General Agreement
		Interconnection Agreement Between CP&L and
	08/03/95	Frontera Generation Limited
		East HVDC Interconnection Facilities Use and
	04/26/85	Maintenance Agreement
		Oklaunion Unit No. 1 Construction ownership
	11/17/97	and Operating Agreement
		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
	06/15/00	Company (as Operator)
	06/15/00	System Integration Agreement
	03/26/99	System Transmission Integration Agreement
		Electric Service Contract between Frontera
		General Limited Partners and Central Power
	01/01/97	and Light
	06/15/00	CSW Operating Agreement
	07/29/97	AEP Co. Inc. and its Consolidated Affiliated
		Tax Agreement regarding methods of allocated
	12/09/04	Consolidated Income Tax
		AEP System Amended and Restated Utility Money
	12/18/02	Pool Agreement
	06/01/96	AEP System Utility Money Pool Agreement
		General Pole Attachment Agreement between
		CP&L and C3 Communications (formerly CSW

AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
		Communications, Inc.)
	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 Regulated Companies
	06/15/00	AEP System Tax Agreement
AEP Texas North Company (Formerly West Texas Utilities)	06/04/97	Abilene/San Angelo Fiber System Agreement between C3 Communications (Formerly CSW Communications) and West Texas Utilities Company
	07/01/96	Pole Attachment License Agreement (West) between West Texas and C3 Communications (Formerly CSW Communications)
	07/01/93	Rail Car Lease Agreement(West)
	10/29/99	Transmission Coordination Agreement (West) Regulated Companies
	06/16/00	Amended and Restated Purchase Purchase Agreement between CSW Credit, Inc. and Affiliate (West) Companies
	06/16/00	Amended and Restated Agency Agreement between CSW Credit, Inc. and Affiliate (West) Companies
	06/01/99	CSW System General Agreement
	12/22/97	Energy Conservation Measure Utility/Energy Service Company Agency Agreement
	09/14/88	Oklaunion HVDC Project Construction, Ownership and Operating Agreement
	04/26/85	Oklaunion Union No 1 Construction, Ownership and Operating Agreement
	06/15/00	System Integration Agreement
	06/15/00	System Transmission Integration Agreement
	01/01/97	CSW Operating Agreement
	06/15/00	American Electric Power Company, Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of allocated consolidated Income Tax
	12/09/04	AEP System Amended and Restated Utility Money

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
		Pool Agreement
	06/26/01	Interconnection Agreement Between West Texas Utilities Company and Indiana Mesa Power Partners II LP
	06/26/01	Interconnection Agreement Between West Texas Utilities Company and Indiana Mesa Power Partners I LP
	06/15/00	AEPSC Service Agreement with West Texas Utilities Company
	12/18/02	AEP System Utility Money Pool Agreement
	07/18/02	Memorandum of understanding (West)between C3 Communications, Inc. and Public Service of Oklahoma, Southwestern Electric, Central Power and Light and West Texas
	03/19/01	Interconnection Agreement/Indian Mesa Power Partners, LP (Desert Sky)
	10/30/01	Construction Agreement/Trent Wind Farm LP
	05/25/06	Purchase and Sale Agreement between CSW Power Marketing, LLC
Appalachian Power Company	07/30/87	Interconnection Agreement
	04/01/84	Transmission Agreement
	07/30/87	Mutual Assistance Agreement
	01/01/79	Central Machine Shop Agreement
	09/15/80	Putnam Coal Transfer Agreement between APCo and OPCo
	04/08/83	AEP Pro Serv, Inc. (Formerly AEP Resources)
	01/01/98	Appalachian Power & Ohio Power (Sporn Plant)
	05/01/86	Barge Transportation Agreement/Ohio Power Company, AEP Generating Company, River Transportation Division of I&M
	03/01/78	Indenture Between APCo and Southern Appalachian Coal Company
	08/14/48	Coal Supply Agreement Between APCo and Central Appalachian Coal
	12/01/76	Indenture Between APCo and Cedar Coal
	09/27/96	AEP Energy Service, Inc. (Formerly AEP Energy Solutions) in a separate agreement with affiliate companies
	03/04/98	AEP Communications, LLC with Affiliate Companies

AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	06/01/78	Racine Hydro Operating Agreement
	04/01/82	AEP Rail Car Use Agreement
	04/01/82	Rail Car Maintenance Agreement
	03/01/98	Pole Attachment License Agreement (EAST)
		between AEP Operating Companies and AEP
		Communications LLC
	03/01/98	Master Site Agreement (East) with AEP
		Operating Companies and AEP Communications
	03/06/97	LLC
		Agreement Between Appalachian Power Company
	10/03/83	and AEP Energy Services Inc.
		Agreement Between Appalachian Power Company
		and AEP Pro Service (Formerly AEP Energy
	06/16/00	Services
		Purchase Agreement Between CSW Credit and
	06/16/00	it's affiliate client companies
		Agency Agreement Between CSW Credit and it's
	06/15/00	affiliated client companies
	06/15/00	System Integration Agreement
	03/04/98	System Transmission Integration Agreement
		Agreement Between Appalachian Power Company
	03/04/98	and AEP Communications
		Agreement between AEP Communications LLC and
	01/27/98	Appalachian Power Company
		Agreement between Appalachian Power, Wheeling
	01/27/98	Power and AEP Communications
		Agreement between AEP Communications, LLC
	02/12/98	Appalachian Power Company and Wheeling Power
		Fiber Optic Agreement (East) with AEP
	06/15/00	Communications
		American Electric Power and it's consolidated
		Affiliated Tax Agreements regarding methods
	08/11/41	of allocating consolidated income taxes
		Land Purchase Contract between APCo and the
	12/09/04	Franklin Real Estate Company
		AEP System Amended and Restated Utility Money
	06/21/96	Pool Agreement
		AEP Modifications No. 1 AEP System Interium
	12/13/00	Allowance Agreement
		Contract number C-11031 Between AEPSC, as

AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
	12/31/96	agent and Sun Technical
	06/15/00	Affiliated Transactions Agreement
	05/04/04	AEPSC Service Agreement with Appalachian
	12/18/02	Power
	02/15/05	Arrangement for the use of the Amos Simulator
		AEP System Utility Money Pool Agreement
		Third Amended and Restated Purchase Agreement
	02/15/05	between AEP Credit and Appalachian Power
		Company
	01/01/05	Third Amended and Restated Agency Agreement
		between AEP Credit and Appalachian Power
		AEP Co, Inc. and it's Consolidated Affiliate
	06/13/08	Tax agreement regarding methods of Allocating
	06/19/08	Consolidated Income Taxes.
		Agreement between APCO and AEPSC
		Amendment No 2 to the Third Amended and
	06/19/08	Restated Purchase Agreement between AEP
		Credit and Appalachian Power
		Amendment No 2 to the Third Amended and
	06/27/08	Restated Agency Agreement between AEP Credit
	06/27/08	and Appalachian Power
	06/27/08	Gypsum Agreement
	09/08/08	AEP System Rail Car Use Agreement
		Rail Car Use Agreement
		Amendment No. 1 and Consent to AEP System Rail Car Use Agreement
	12/09/04	Money Pool Agreement, Amended and Restated Agreement
Columbus Southern Power Company	04/27/87	Interconnection Agreement
	04/01/84	Transmission Agreement
	07/30/87	Mutual Assistance Agreement
	04/08/83	AEP Pro Serv, Inc.(Formerly AEP Resources Service Company, AEP Energy Services, Inc. in separate agreements with Wheeling Power, Columbus Southern Power, Indiana Michigan Power, Kentucky Power, Kingsport Power, Ohio Power and Appalachian Power Company
	08/01/86	Amended Coal Washing Agreement/Conesville Coal Preparation

AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	01/01/97	Amendment 1 to the Amended Coal Washing Agreement
	03/04/98	AEP Communications LLC with Affiliate Companies
	03/01/98	Pole Attachment License Agreement/AEP Communications LLC
	03/01/98	Master Site Agreement (East) with AEP Operating Companies and AEP Communication LLC
	09/27/96	Agreement between Columbus Southern Power and AEP Energy Services
	04/08/83	Agreement between Columbus Southern Power and AEP ProServ
	06/16/00	Purchase Agreement between AEP Credit and it's affiliates
	06/16/00	Agency Agreement between AEP Credit and it's affiliates
	06/15/00	System Integration Agreement
	06/15/00	System Transmission Integration Agreement
	02/12/98	Agreement between Columbus Southern Power, Ohio Power and AEP Communications, LLC
	02/12/98	Agreement between AEP Communication, Columbus Southern Power and Ohio Power Company
	02/12/98	Fiber Optic Agreement/AEP Communications
	06/15/00	AEP Co, Inc. and it Consolidated Affiliate Tax Agreements regarding methods of Allocation Consolidated Income Taxes
	02/05/81	Purchase Contract Agreement between Columbus Southern Power and Franklin Real Estate
	12/09/04	AEP System Amended and Reinstated Utility Money Pool Agreement
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	12/13/00	Contract Number C-11031 between AEP as Agent and Sun Technical Services Inc.
	12/31/96	Affiliate Transaction Agreement (East Companies)
	05/04/04	Arrangement for the use of the Amos Simulator
	06/15/00	AEPSC Service Agreement with Columbus Southern Power
	12/18/02	AEP System Utility Money Pool Agreement
	02/15/05	Third Amended and Reinstated Purchase

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
		Agreement between AEP Credit and Columbus Southern Power
	02/15/05	Third Amended and Restated Agency Agreement
	01/01/05	between AEP Credit and Columbus Southern Power, American Electric Power Company, Inc. and its consolidated affiliate tax agreements regarding methods of allocating consolidated income taxes
		Central Machine Shop Agreement/Appalachian
	01/01/79	Power
		Unit Power Agreement between AEP Generating
	08/14/07	Company (Lawrenceburg) and Columbus Southern Power Company
Indiana Michigan Power Company	04/27/87	Interconnection Agreement
	04/01/84	Transmission Agreement
	07/30/87	Mutual Assistance Agreement
	04/08/83	AEP Pro Serv, Inc.
	05/01/86	Barge Transportation Agreement and Appendix A
	03/01/82	Coal Supply Agreement/Blackhawk Coal
	10/21/85	Amendment to Coal Supply Agreement/Blackhawk Coal
	09/27/96	AEP Energy Services, Inc.
	03/04/98	AEP Communications, LLC with Affiliate Companies
	04/01/82	AEP Rail Car Use Agreement
	04/01/82	Rail Car Maintenance Agreement
	03/01/98	Pole Attachment License Agreement (East)
	03/01/98	Master Site Agreement (East) with AEP Operating Companies and AEP Communications
	06/17/83	Cook Coal Terminal Coal Transfer Agreement
	09/27/96	Agreement Between Indiana Michigan Power and AEP Communications
	04/08/83	Agreement Between Indiana Michigan Power and AEP ProServ
	06/16/00	Purchase Agreement Between CSW Credit and it's Affiliate Client Companies
	06/16/00	Agency Agreement Between CSW Credit and it's Affiliate Client Companies

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	02/15/99	Contract Number B-10024 Between Indiana Michigan Power and Sun Technical Services Inc
	04/01/99	Master Services Agreement - Contract 10047 between Indiana Michigan Power and Sun Technical Services Inc.
	12/14/98	Contract Number A-8709 Between Indiana Michigan Power and Sun Technical Services, Inc.
	06/15/00	System Integration Agreement
	06/15/00	System Transmission Integration Agreement
	10/14/98	Agreement Between Indiana Michigan Power and AEP Communications, Inc.
	10/14/98	Agreement Between AEP Communications and Indiana Michigan Power
	02/12/98	Fiber Optic Agreement/AEP Communications
	06/15/00	American Electric Power Company, Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	04/30/48	Purchase Contract between Indiana Franklin Realty, Inc.
	04/04/50	Purchase Contract between The Franklin Real Estate Company.
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	01/01/01	Master Services Agreement - Contract C11059 Between Indiana and Michigan Power Company and Sun Technical
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	12/31/96	Affiliated Transactions Agreement (East Companies)
	04/21/04	Agency Agreement Between CSW Credit and Indiana Michigan Power Company
	05/04/04	Unit Power Agreement Amendment No 1 between I&M and AEP
	05/04/04	Arrangement for the use of the Amos Simulator
	05/04/04	Fiber Optic Agreement Between AEP Communications, LLC and I&M
	05/04/04	Unit 2 Operating Agreement between I&M and AEG

AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	06/15/00	AEPSC Service Agreement with Indiana Michigan Power Company
	12/18/02	AEP System Utility Money Pool Agreement
	02/15/05	Third Amended and Restated Purchase Agreement
	02/15/05	Third Amended and Restated Agency Agreement
	06/15/00	AEP Co. Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	08/08/07	Indiana Michigan Power Company & AEP Generating Company Operation and Maintenance Agreement
	06/27/08	AEP System Rail Car Use Agreement
	06/27/08	Rail Car Use Agreement
	09/08/08	Amendment No 1 and Consent to AEP System Rail Car Agreement
	01/01/79	Central Machine Shop Agreement/Appalachian Power
	10/14/98	AEP Communications & Wheeling Power (Operating Company as Client)
	10/14/98	AEP Communications & Wheeling Power (AEP Communications as Client)
Kentucky Power Company	04/27/87	Interconnection Agreements
	04/01/84	Transmission Agreement
	07/30/87	Mutual Assistance Agreement
	04/08/83	AEP Pro Serv, Inc.
	09/27/96	AEP Energy Services, Inc.
	03/04/98	AEP Communications, LLC with Affiliate Companies
	03/01/98	Pole Attachment License Agreement/AEP Communications LLC
	03/01/98	Master Site Agreements (East) With AEP Operating Companies
	07/07/83	Agreement Between Kentucky Power and ProServ
	06/16/00	Purchase Agreement between AEP Credit and it's Affiliate Client Companies
	06/16/00	Agency Agreement between AEP Credit and it's Affiliated Client Companies
	06/15/00	System Integration Agreement
	06/15/00	System Transmission Integration Agreement
	11/18/97	Agreement between AEP Communications, LLC and

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
		Kentucky Power
	11/18/97	Agreement between Kentucky Power and AEP Communications, LLC
	02/12/98	Fiber Optic Agreement (East) with AEP Communications
	06/15/00	AEP Co. Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	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.
	12/09/04	AEP System Amended and Restated Money Pool Agreement
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	12/09/04	Affiliated Transactions Agreement (East Companies)
	05/04/04	Arrangement for the Use of the Amos Simulator
	06/15/00	AEPSC Service Agreement with Kentucky Power
	12/18/02	AEP System Utility Money Pool Agreement
	02/15/05	Third Amended and Restated Purchase Agreement Between AEP Credit and Kentucky Power
	02/15/05	Third Amended and Restated Agency Agreement Between AEP Credit and Kentucky Power
	01/01/05	American Electric Power Company, Inc. and it's Consolidated Affiliated Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	01/01/79	Central Machine Shop Agreement/Appalachian Power
Kingsport Power Company	07/30/87	Mutual Assistance Agreement
	04/07/83	AEP Pro Serv, Inc. (Formerly AEP Resources)
	09/27/96	AEP Energy Services, Inc. (Formerly AEP Energy Services)
	03/01/98	Master Site Agreement (East) with AEP Operating Companies
	09/27/96	Agreement Between Kingsport Power Company and AEP Energy Services

AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	07/07/83	Agreement Between Kingsport Power Company and AEP ProServ
	06/16/00	Purchase Agreement Between CSW Credit and Affiliate Client Companies
	06/16/00	Agency Agreement Between CSW Credit and Affiliate Client Companies
	06/15/00	AEP Co, Inc and it's Consolidated Affiliate Tax Agreement regarding methods of Allocating Consolidated Income Tax
	01/01/72	Purchase Contract Between KGPCO and Indiana Franklin Realty, Inc.
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	12/31/96	Affiliate Transactions Agreement (East Companies)
	06/15/00	AEPSC Service Agreement with Kingsport Power
	12/18/02	AEP System Utility Money Pool Agreement
	02/15/05	Third Amended and Restated Purchase Agreement Between AEP Credit and Kingsport Power
	02/15/05	Third Amended and Restated Agency Agreement Between AEP Credit and Kingsport Power
	01/01/05	American Electric Power Company, Inc. and it's Consolidated Affiliate Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	01/01/79	Central Machine Shop Agreement/Appalachian Power
Ohio Power Company	04/27/87	Interconnection Agreement
	04/01/84	Transmission Agreement
	07/30/87	Mutual Assistance Agreement
	09/15/90	Putnam Coal Transfer Agreement Between APCo and OPCo
	04/08/83	AEP Pro Serv, Inc. (Formerly AEP Resources)
	01/01/98	Appalachian Power & Ohio Power (Sporn Plant)
	05/01/86	Barge Transportation Agreement and Appendix A
	02/01/74	Supplemental Indenture OPCo, Ohio Electric, Southern Ohio Electric Co. (Relating to Delivery of Coal from Meigs
	09/27/96	AEP Energy Services, Inc.
	03/04/98	AEP Communications, LLC with Affiliated Companies

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	07/26/73	Buckeye Power Agreement
	06/01/78	Racine Hydro Operating Agreement
	04/01/82	AEP Rail Car Use Agreement
	04/01/82	Rail Car Maintenance Agreement/APCO & I&M
	10/01/72	Indenture Agreement Between Ohio Power and Southern Ohio Coal
	04/01/83	Amended and Restated Coal Supply Agreement between Ohio Power and Central Ohio Coal
	03/01/98	Pole Attachment License Agreement/AEP Communications LLC
	03/01/98	Master Site Agreement (East) with AEP Operating Companies
	06/17/83	Cook Coal Terminal Coal Transfer Agreement
	09/27/96	Agreement between Ohio Power Company and AEP Energy Services
	04/08/83	Agreement between Ohio Power Company and AEP Pro Serv, Inc
	06/16/00	Purchase Agreement Between CSW Credit and Affiliate Client Companies
	06/16/00	Agency Agreement Between CSW Credit and Affiliate Client Companies
	06/15/00	System Integration Agreement
	06/15/00	System Transmission Integration Agreement
	02/12/98	Agreement Between Columbus Southern Power, Ohio Power and AEP Communications
	02/12/98	Fiber Optic Agreement/AEP Communications
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliate Tax Agreement regarding Methods of Allocating Consolidated Income Taxes
	08/11/41	Land Purchase Contract/Franklin Real Estate Company
	11/25/70	Purchase Contract/Indiana Franklin Realty, Inc.
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	06/21/96	AEP Modifications No. 1 AEP System Interim Allowance Agreement
	12/31/96	Affiliated Transactions Agreement (East Companies)
	05/04/04	Arrangement for the Use of the Amos Simulator

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	06/15/00	AEPSC Service Agreement with Ohio Power
	12/18/02	AEP System Utility Money Pool Agreement
	02/15/05	Third Amended and Restated Purchase Agreement
	02/15/05	Third Amended and Restated Agency Agreement
	06/15/00	AEP Co, Inc and It's Consolidated Affiliate Tax Agreement regarding methods of Allocating Consolidated Income Taxes
	06/27/08	Gypsum and Purge Stream Waste Disposal Agreement
	06/27/08	AEP System Rail Car Use Agreement
	06/27/08	Rail Car Use Agreement
	09/08/08	Amendment No 1 and Consent to AEP System Rail Car Use Agreement
	01/01/79	Central Machine Shop Agreement/Appalachian Power
	07/26/73	Amos Unit No.3
Public Service Company of Oklahoma	07/01/93	Rail Car Lease Agreement(West)
	07/29/97	Rail Car Maintenance Facility Agreement
	10/29/99	Transmission Coordination Agreement(West)
	06/16/00	Amended and Restated Purchase Agreement Between CSW Credit and it's Affiliates
	06/16/00	Amended and Restated Agency Agreement between CSW Credit and it's Affiliates
	06/01/99	CSW System General Agreement
	08/03/95	East HVDC Interconnection Agreement/West Regulated Companies
	09/14/88	Oklaunion HVDC Project Construction, Ownership and Operating Agreement
	04/26/85	Oklaunion Unit No. 1 Construction, Ownership and Operating Agreement
	06/15/00	System Integration Agreement
	06/15/00	System Transmission Integration Agreement
	01/01/97	CSW Operating Agreement
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliate Tax Agreements
	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

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-06**

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	*DATE*	*CONTRACT*
		Public Service Company of Oklahoma
	12/09/04	AEP System Amended and Restated Money Pool Agreement
	06/15/00	AEPSC Service Agreement with Public Service Company of Oklahoma
	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
	12/21/01	Operating Agreement-PSO, SWEPCO, AEPSC
	11/16/04	Interconnection Agreement (Ercot Generation) Between AEPTN and PSO
	12/18/02	AEP System Utility Money Pool Agreement
	12/18/02	Third Amended and Restated Agency Agreement
	12/18/02	Third Amended and Restated Purchase Agreement
	01/01/05	American Electric Power Company, and it's Consolidated Tax Affiliates
	05/01/06	Operating Agreement PSO, SWEPCO and AEPSC
	09/08/08	Amendment No 1 and consent to AEP System Rail Car Use Agreement
	07/08/09	Memorandum of Understanding (West) Between C3 Communications, Inc., Public Service Company
	01/30/08	of Oklahoma, Southwestern Electric Power
	01/30/08	Company, Central Power and Light, and West
	01/09/04	Texas Utilities.
Southwestern Electric Power Company	05/31/01	Lignite Mining Agreement
	07/01/93	Rail Car Lease Agreement (West)
	07/29/97	Rail Car Maintenance Facility Agreement (West)
	10/29/99	Transmission Coordination Agreement (West)
	06/16/00	Amended and Restated Purchase Agreement Between CSW and Affiliate (West) Companies
	06/16/00	Amended and Restated Agency Agreement Between CSW Credit and it's Affiliate Agreements
	06/01/99	CSW System General Agreement
	08/03/95	East HVDC Interconnection Use and Maintenance Agreement
	06/15/00	System Integration Agreement

AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	06/15/00	System Transmission Integration Agreement
	01/01/97	CSW Operating Agreement
	06/15/00	American Electric Power Company, Inc. and its Consolidated Affiliates Tax Agreements
	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
	07/16/01	Agreement Between Southwestern Electric Power Company and C3 Communications
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	08/06/02	Interconnection Agreement Between SWEPCo and Eastex Cogeneration LP
	06/15/00	AEPSC Service Agreement with Southwest Power Electric
	07/25/03	Second Amended and Restated Agency Agreement Between AEP Credit and SWEPCo
	07/25/03	Second Amended and Restated Purchase Agreement Between AEP Credit and SWEPCo
	12/21/01	Operating Agreement PSO, SWEPCo, AEPSC
	12/18/02	AEP System Utility Money Pool Agreement
	02/15/05	Third Amended and Restated Purchase Agreement Between AEP Credit and Southwestern Electric Power
	02/15/05	Third Amended and Restated Agency Agreement Between AEP Credit and Southwestern Electric Power
	01/01/05	American Electric Power Company, Inc. and Its Consolidated Affiliated Tax Agreements
	05/01/06	Operating Agreement PSO, SWEPCO, AEPSC
	09/08/08	Amendment No 1 and Consent to AEP System Rail Car Use
	07/08/99	Memorandum of Understanding (West) Between C3 Communications, Public Service Company,

AEP AMERICAN ELECTRIC POWER

Document Number 99-00-06

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
Wheeling Power Company	08/11/41	Land Purchase Contract/The Franklin Real Estate Company
	07/01/96	Pole Attachment License Agreement/AEP Communications LLC
	07/01/93	Railcar Lease Agreement (West)
	10/29/99	Transmission Coordination Agreement (West)
	06/16/00	Amended and Restated Purchase Agreement between CSW Credit and Affiliate (West) Companies
	06/16/00	Amended and Restated Agency Agreement Between CSW Credit and Affiliate (West) Companies
	06/01/99	CSW System General Agreement
	12/22/97	Energy Conservation Measure Utility/Energy Service Company Agency Agreement
	09/14/88	Oklaunion HVDC Project Construction, Ownership and Operating Agreement
	04/26/85	Oklaunion Unit No 1 Construction, Ownership and Operating
	06/15/00	System Integration Agreement
	06/15/00	System Transmission Integration Agreement
	01/01/97	CSW Operating Agreement
	06/15/00	American Electric Power Company, Inc. and it's Consolidated Affiliated Tax Agreement Regarding Methods of Allocating Taxes
	12/09/04	AEP System Amended and Restated Utility Money Pool Agreement
	06/26/01	Interconnection Agreement Between West Texas Utilities and Indian Mesa Power Partners II LP
	06/26/01	Interconnection Agreement Between West Texas Utilities and Indian Mesa Power Partners I LP
	06/15/00	AEPSC Service Agreement with West Texas Utilities
	12/18/02	AEP System Utility Money Pool Agreement
	07/08/99	Memorandum of Understanding (West) Between C3 Communication, Public Service Company of Oklahoma, Southwestern Electric Power Company, Central Power and Light Company and West Texas Utilities
	01/01/79	Central Machine Shop Agreement/Appalachian Power

AEP AMERICAN ELECTRIC POWER

Document Number **99-00-06**

Cost Allocation Manual

Section

Appendix

Subject

LIST OF AFFILIATE CONTRACTS BY COMPANY

COMPANY NAME	DATE	CONTRACT
	10/03/83	AEP Pro Serv, Inc.
	07/30/87	Mutual Assistance Agreement
	12/31/96	Affiliated Transactions Agreement
	01/09/97	AEP Energy Services, Inc.
	01/27/98	AEP Communications (Operating Company as Client)
	01/27/98	AEP Communications (AEP Communications as Client)
	01/27/98	Fiber Optic Agreement/AEP Communications
	08/15/08	AEPSC Service Agreement
	--/--/--	AEP System Tax Agreement
	12/09/04	Money Pool Agreement, Amended and Restated
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

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DEC 29 2009

PUBLIC SERVICE
COMMISSION

Kentucky Power Company

2009 First Quarter Report

KPSC Case No. 2009-00459
Pursuant to 807 KAR5:001
Section 10 (6) (s)
2009 First Qtr. Report
2009 Second Qtr. Report
2009 Third Qtr. Report

Financial Statements

AMERICAN ELECTRIC POWER

TABLE OF 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.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
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.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
FSP	FASB Staff Position.
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	Public Utility Commission of Texas.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SECA	Seams Elimination Cost Allocation.

Term	Meaning
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SIA	System Integration Agreement.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
REVENUES		
Electric Generation, Transmission and Distribution	$ 161,249	$ 147,059
Sales to AEP Affiliates	15,423	20,053
Other	1,761	178
TOTAL	178,433	167,290
EXPENSES		
Fuel and Other Consumables Used for Electric Generation	53,041	49,211
Purchased Electricity for Resale	8,617	3,766
Purchased Electricity from AEP Affiliates	48,186	54,190
Other Operation	12,038	15,508
Maintenance	21,345	9,920
Depreciation and Amortization	12,807	11,958
Taxes Other Than Income Taxes	2,346	1,180
TOTAL	158,380	145,733
OPERATING INCOME	20,053	21,557
Other Income (Expense):		
Interest Income	50	1,288
Allowance for Equity Funds Used During Construction	(22)	344
Interest Expense	(7,310)	(6,855)
INCOME BEFORE INCOME TAX EXPENSE	12,771	16,334
Income Tax Expense	3,317	5,190
NET INCOME	$ 9,454	$ 11,144

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

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(2,500)		(2,500)
TOTAL					384,104
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,258				(2,335)	(2,335)
NET INCOME			11,144		11,144
TOTAL COMPREHENSIVE INCOME					8,809
MARCH 31, 2008	$ 50,450	$ 208,750	$ 136,862	$ (3,149)	$ 392,913
DECEMBER 31, 2008	$ 50,450	$ 208,750	$ 138,749	$ 59	$ 398,008
Common Stock Dividends			(6,750)		(6,750)
TOTAL					391,258
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $134				249	249
NET INCOME			9,454		9,454
TOTAL COMPREHENSIVE INCOME					9,703
MARCH 31, 2009	$ 50,450	$ 208,750	$ 141,453	$ 308	$ 400,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
March 31, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 676	$ 646
Accounts Receivable:		
Customers	17,976	24,214
Affiliated Companies	7,440	6,721
Miscellaneous	133	83
Allowance for Uncollectible Accounts	(1,158)	(1,144)
Total Accounts Receivable	24,391	29,874
Fuel	27,154	29,440
Materials and Supplies	10,763	10,630
Risk Management Assets	14,658	13,760
Accrued Tax Benefits	6,689	41
Regulatory Asset for Under-Recovered Fuel Costs	9,940	9,953
Margin Deposits	7,917	5,207
Prepayments and Other	2,591	5,710
TOTAL	104,779	105,261
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	539,736	533,998
Transmission	434,353	431,835
Distribution	541,428	528,711
Other	63,683	65,485
Construction Work in Progress	35,580	46,650
Total	1,614,780	1,606,679
Accumulated Depreciation and Amortization	487,768	476,568
TOTAL - NET	1,127,012	1,130,111
OTHER NONCURRENT ASSETS		
Regulatory Assets	180,364	179,845
Long-term Risk Management Assets	12,967	10,860
Deferred Charges and Other	38,776	41,884
TOTAL	232,107	232,589
TOTAL ASSETS	$ 1,463,898	$ 1,467,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
March 31, 2009 and December 31, 2008
(Unaudited)

	2009	2008
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 157,290	$ 131,399
Accounts Payable:		
General	45,980	35,584
Affiliated Companies	14,776	45,245
Risk Management Liabilities	7,640	6,316
Customer Deposits	16,875	15,985
Accrued Taxes	8,486	11,903
Other	21,520	29,526
TOTAL	272,567	275,958
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,597	398,555
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	6,024	5,630
Deferred Income Taxes	264,648	259,666
Regulatory Liabilities and Deferred Investment Tax Credits	37,526	46,135
Deferred Credits and Other	63,575	64,009
TOTAL	790,370	793,995
TOTAL LIABILITIES	1,062,937	1,069,953
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	141,453	138,749
Accumulated Other Comprehensive Income (Loss)	308	59
TOTAL	400,961	398,008
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,463,898	$ 1,467,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Three Months Ended March 31, 2009 and 2008
(in thousands)
(Unaudited)

		2009		2008
OPERATING ACTIVITIES				
Net Income	$	9,454	$	11,144
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:				
Depreciation and Amortization		12,807		11,958
Deferred Income Taxes		10,516		(979)
Allowance for Equity Funds Used During Construction		22		(344)
Mark-to-Market of Risk Management Contracts		(906)		(749)
Change in Other Noncurrent Assets		2,883		(888)
Change in Other Noncurrent Liabilities		(1,268)		246
Changes in Certain Components of Working Capital:				
Accounts Receivable, Net		5,483		3,292
Fuel, Materials and Supplies		2,153		(5,663)
Accounts Payable		(16,213)		(5,119)
Customer Deposits		890		532
Accrued Taxes, Net		(10,065)		811
Other Current Assets		(3,329)		2,748
Other Current Liabilities		(11,660)		(7,618)
Net Cash Flows from Operating Activities		767		9,371
INVESTING ACTIVITIES				
Construction Expenditures		(19,859)		(27,784)
Proceeds from Sales of Assets		161		129
Net Cash Flows Used for Investing Activities		(19,698)		(27,655)
FINANCING ACTIVITIES				
Change in Advances from Affiliates, Net		25,891		21,152
Principal Payments for Capital Lease Obligations		(180)		(206)
Dividends Paid on Common Stock		(6,750)		(2,500)
Net Cash Flows from Financing Activities		18,961		18,446
Net Increase in Cash and Cash Equivalents		30		162
Cash and Cash Equivalents at Beginning of Period		646		727
Cash and Cash Equivalents at End of Period	$	676	$	889
SUPPLEMENTARY INFORMATION				
Cash Paid for Interest, Net of Capitalized Amounts	$	17,080	$	10,934
Net Cash Paid (Received) for Income Taxes		336		(354)
Noncash Acquisitions Under Capital Leases		49		84
Construction Expenditures Included in Accounts Payable at March 31,		5,802		6,846

See Condensed Notes to Condensed Financial Statements.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Derivatives, Hedging and Fair Value Measurements
8. Income Taxes
9. Financing Activities

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. The net income for the three months ended March 31, 2009 are not necessarily indicative of results that may be expected for the year ending December 31, 2009. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2008 financial statements and notes thereto, which are included in KPCo's 2008 Annual Report.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. 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 and other factors. Management believes that the significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

KPCo holds a significant variable interest in AEPSC and AEGCo. AEPSC provides certain managerial and professional services to KPCo. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo at AEPSC's cost. KPCo has not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and KPCo that could require additional financial support from KPCo or expose it to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo is exposed to losses to the extent it cannot recover the costs of AEPSC through its normal business operations. KPCo is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. 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. Total billings from AEPSC for the three months ended March 31, 2009 and 2008 were $8 million and $10 million, respectively. The carrying amount of liabilities associated with AEPSC for the three months ended March 31, 2009 and for the year ended December 31, 2008 were $2 million and $5 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, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. KPCo has no involvement with AEGCo's interest in the Lawrenceburg Generating Station. 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 the nature of the AEP Power Pool, there is a sharing of the cost of Rockport Plant such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport Plant. 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, 2009 and 2008 were $27 million and $25 million, respectively. The carrying amount of liabilities associated with AEGCo for the three months ended March 31, 2009 and for the year ended December 31, 2008 were $8 million and $9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Revenue Recognition – Traditional Electricity Supply and Demand

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on its Condensed Consolidated Statements of Income upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies then purchase power from PJM to supply their customers. Generally, these power sales and purchases are reported on a net basis as revenues on KPCo's Condensed Statements of Income. However, in the first quarter of 2009, there were times when the AEP East companies were purchasers of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale on KPCo's Condensed Statements of Income.

Physical energy purchases, including those from RTOs, that are identified as non-trading, are accounted for on a gross basis in Purchased Electricity for Resale on KPCo's Condensed Statements of Income.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of new pronouncements issued or implemented in 2009 and standards issued but not implemented that management has determined relate to KPCo's operations.

Pronouncements Adopted During the First Quarter of 2009

The following standards were effective during the first quarter of 2009. Consequently, the financial statements and footnotes reflect their impact.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. KPCo does not have any such tax positions that result in adjustments.

In April 2009, the FASB issued FSP SFAS 141(R)-1 "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." The standard clarifies accounting and disclosure for contingencies arising in business combinations. It was effective January 1, 2009.

KPCo adopted SFAS 141R, including the FSP, effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. KPCo will apply it to any future business combinations.

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

KPCo adopted SFAS 160 effective January 1, 2009 with no impact on its financial statements or footnote disclosures.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of the primary underlying risk and accounting designation.

KPCo adopted SFAS 161 effective January 1, 2009. This standard increased disclosures related to derivative instruments and hedging activities. See "Derivatives and Hedging " section of Note 7 for further information.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

KPCo adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

KPCo adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

KPCo adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2)

In February 2008, the FASB issued SFAS 157-2 which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. 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.

KPCo adopted SFAS 157-2 effective January 1, 2009. KPCo will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analysis related to long-lived assets, equity investments, goodwill and intangibles. KPCo did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first quarter of 2009.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments" (FSP SFAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments.

This standard is effective for interim periods ending after June 15, 2009. Management expects this standard to increase the disclosure requirements related to financial instruments. KPCo will adopt the standard effective second quarter of 2009.

FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP SFAS 115-2 and SFAS 124-2)

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2 amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements.

This standard is effective for interim periods ending after June 15, 2009. Management does not expect a material impact as a result of the new OTTI evaluation method for debt securities, but expects this standard to increase the disclosure requirements related to financial instruments. KPCo will adopt the standard effective second quarter of 2009.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. KPCo will adopt the standard effective for the 2009 Annual Report.

FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4)

In April 2009, the FASB issued FSP SFAS 157-4 providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods.

This standard is effective for interim and annual periods ending after June 15, 2009. Management expects this standard to have no impact on the financial statement but will increase disclosure requirements. KPCo will adopt the standard effective second quarter of 2009.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, insurance, hedge accounting, discontinued operations, trading inventory and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

3. RATE MATTERS

As discussed in KPCo's 2008 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2008 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 2009 and updates KPCo's 2008 Annual Report.

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis, these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that it has the authority to provide for surcharges and surcredits until the court of appeals rules otherwise.

In November 2008, the Kentucky Court of Appeals concluded that Duke Energy's surcharge was illegal. However, the order stated that the "decision was premised on the nature of the long-term capital improvements proposed by Duke Energy as distinguished from the fuel increases that are fluctuating and unanticipated. The latter have been approved by the Kentucky Supreme Court and remain the law." In February 2009, the Kentucky Court of Appeals denied the KPSC request for appeal of the Franklin County Circuit Court decision. In March 2009, the KPSC filed for a discretionary review of the related Duke Energy case with the Kentucky Supreme Court. Management believes that all of KPCo's variable rate mechanisms are valid and would be upheld if ever challenged.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. KPCo's portion of recognized gross SECA revenues was $17 million.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers are engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion of any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. KPCo provided reserves of $2.9 million and $400 thousand in 2006 and 2007, respectively.

In February 2009, a settlement agreement was approved by the FERC resulting in the completion of a $1 million settlement applicable to $20 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $10 million applicable to $112 million of SECA revenues. The balance in the reserve for future settlements as of March 2009 was $34 million. KPCo's reserve balance at March 31, 2009 was $2.6 million. As of March 31, 2009, there were no in-process settlements.

If the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. If the remaining unsettled SECA claims are settled for considerably more than the to-date settlements or if the remaining unsettled claims are awarded a refund by the FERC greater than the remaining reserve balance, it could have an adverse effect on net income. Cash flows will be adversely impacted by any additional settlements or ordered refunds. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain state regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. In January and March 2009, AEP received retail rate increases in Tennessee and Indiana, respectively, that recognized the higher retail transmission costs resulting from the loss of wholesale transmission revenues from T&O transactions. As a result, AEP is now recovering approximately 98% of the lost T&O transmission revenues. The remaining 2% is being incurred by I&M until it can revise its rates in Michigan to recover the lost revenues.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings to reflect the resultant additional transmission cost reductions. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, established a settlement proceeding with an ALJ, and delayed the requested October 2008 effective date for five months. The requested increase, which the AEP East companies began billing in April 2009 for service as of March 1, 2009, will produce a $63 million annualized increase in revenues. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies' transmission facilities so that retail rates for jurisdictions other than Ohio are not directly affected. In October 2008, AEP filed the required compliance filing, and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing. Under the formula, rates will be updated effective July 1, 2009, and each year thereafter. Also, beginning with the July 1, 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies shared a portion of such revenues with their wholesale and retail customers during the period June 2000 to March 2006. In December 2008, the AEP West companies recorded a provision for refund. Management cannot predict the outcome of the requested FERC rehearing proceeding or any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding future regulatory proceedings is adequate.

Transmission Equalization Agreement (TEA)

Certain transmission equipment placed in service in 1998 in KPCo's service territory was inadvertently excluded from the AEP East companies' TEA calculation. As a result, KPCo did not receive a TEA credit for this equipment from the other TEA member companies. The amount involved is $7 million annually. It was not discovered until February 2009. KPCo's base electric rates were adjusted only once, in April 2006, during the period in which the error was in effect. In 2009, the allocation was revised to give KPCo its full TEA credit, effective January 2009, and the KPSC staff and attending intervenors were informed about the revision at a meeting in April 2009. Management does not believe that it is probable that a material retroactive rate adjustment will result. However, if a retroactive adjustment is required, it could have an adverse effect on future net income, cash flows and financial condition.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2008 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to March 31, 2009, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, KPCo will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into replacement leasing arrangements for the equipment affected by this notification prior to the termination date of 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At March 31, 2009, the maximum potential loss for these lease agreements was approximately $317 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

CONTINGENCIES

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. Management asserted claims against certain companies that sold power to KPCo and other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities. Management is unable to predict the outcome of these proceedings or their impact on future net income and cash flows.

5. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the three months ended March 31, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 10	$ 10
Interest Cost	63	63	27	28
Expected Return on Plan Assets	(80)	(84)	(20)	(28)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	15	9	11	3
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 20

The following table provides KPCo's net periodic benefit cost for the plans for the three months ended March 31, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended March 31,		Three Months Ended March 31,	
	2009	2008	2009	2008
	(in thousands)			
Net Periodic Benefit Cost	$ 555	$ 249	$ 808	$ 401

AEP sponsors several trust funds with significant investments intended to provide for future pension and OPEB payments. All of the trust funds' investments are well-diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts has declined from the December 31, 2008 balances due to decreases in the equity and fixed income markets. Although the asset values are currently lower than at year end, this decline has not affected the funds' ability to make their required payments.

6. BUSINESS SEGMENTS

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

7. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

DERIVATIVES AND HEDGING

Objectives for Utilization of Derivative Instruments

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

Strategies for Utilization of Derivative Instruments to Achieve Objectives

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal SFAS 133 hedging strategies. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under SFAS 133. Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of SFAS 133.

AEPSC, on behalf of KPCo, enters into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, 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. 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 March 31, 2009:

Notional Volume of Derivative Instruments
March 31, 2009

Primary Risk Exposure	Volume	Unit of Measure
	(in thousands)	
Commodity:		
Power	20,706	MWHs
Coal	1,692	Tons
Natural Gas	7,647	MMBtus
Heating Oil and Gasoline	227	Gallons
Interest Rate	$ 8,279	USD
Interest Rate	$ -	USD

Fair Value Hedging Strategies

At certain times, AEPSC, on behalf of KPCo, enters into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These 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. During 2009 and 2008, this strategy was not actively employed.

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 electricity, coal and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. KPCo 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. During 2009 and 2008, KPCo designated cash flow hedging relationships using these commodities.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial gasoline and heating oil derivative contracts in order mitigate price risk of future fuel purchases. KPCo does not hedge all of fuel price risk. During 2009, KPCo designated cash flow hedging strategies of forecasted fuel purchases. This strategy was not active for KPCo during 2008. For disclosure purposes, these contracts are included with other hedging activity as "Commodity."

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated 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. During 2009 and 2008, KPCo did not have any active interest rate cash flow hedge strategies.

Accounting for Derivative Instruments and the Impact on KPCo's Financial Statements

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet 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 FSP FIN 39-1, 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, 2009 and December 31, 2008 balance sheets, KPCo netted $5 million and $468 thousand of cash collateral received from third parties against short-term and long-term risk management assets and $7.3 million and $1.2 million of cash collateral paid to third parties against short-term and long-term risk management liabilities, respectively.

The following table represents the gross fair value impact of KPCo's derivative activity on the Condensed Balance Sheet as of March 31, 2009.

Fair Value of Derivative Instruments
March 31, 2009
(in thousands)

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency**	**Other (b)**	**Total**
Current Risk Management Assets	$ 131,854	$ 1,621	$ -	$ (118,817)	$ 14,658
Long-Term Risk Management Assets	54,478	124	-	(41,635)	12,967
Total Assets	186,332	1,745	-	(160,452)	27,625
Current Risk Management Liabilities	126,479	406	-	(119,245)	7,640
Long-Term Risk Management Liabilities	50,905	84	-	(44,965)	6,024
Total Liabilities	177,384	490	-	(164,210)	13,664
Total MTM Derivative Contract Net Assets (Liabilities)	$ 8,948	$ 1,255	$ -	$ 3,758	$ 13,961

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented in the Condensed Balance Sheets on a net basis in accordance with FIN 39 "Offsetting of Amounts Related to Certain Contracts."

(b) Amounts represent counterparty netting of risk management contracts, associated cash collateral in accordance with FSP FIN 39-1 and dedesignated risk management contracts.

The table below presents KPCo's MTM activity of derivative risk management contracts for the three months ended March 31, 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
For the Three Months Ended March 31, 2009

Location of Gain (Loss)	**(in thousands)**
Electric Generation, Transmission and Distribution Revenues	$ 8,049
Sales to AEP Affiliates	(1,526)
Regulatory Assets	-
Regulatory Liabilities	1,464
Total Gain on Risk Management Contracts	$ 7,987

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the Condensed Consolidated 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, KPCo 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. Realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in KPCo's Condensed Statements of Income. 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. Unrealized and 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 SFAS 71.

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), KPCo recognizes 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 in Net Income during the period of change.

KPCo records realized 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, 2009 and 2008, this strategy was not actively employed.

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) in accordance with SFAS 71.

Realized gains and losses on derivatives transactions for the purchase and sale of electricity, 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 in KPCo's Condensed Statements of Income, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to commodities. During the three months ended March 31, 2009 and 2008, KPCo recognized immaterial amounts in Net Income related to hedge ineffectiveness.

Beginning in 2009, KPCo executed financial heating oil and gasoline derivative contracts to hedge the price risk of its diesel fuel and gasoline purchased. KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Other Operation and Maintenance Expense or Depreciation and Amortization Expense, as it relates to Capital projects, on the Condensed Statements of Income. KPCo does not hedge all fuel price exposure. During the three months ended March 31, 2009, KPCo recognized no hedge ineffectiveness related to this hedge strategy.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three months ended March 31, 2009 and 2008, this strategy was not actively employed.

The following table provides details on designated, effective cash flow hedges included in AOCI on KPCo's Condensed Balance Sheets and the reasons for changes in cash flow hedges from January 1, 2009 to March 31, 2009. 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, 2009
(in thousands)

	Commodity	Interest Rate	Total
Beginning Balance in AOCI as of January 1, 2009	$ 584	$ (525)	$ 59
Changes in Fair Value Recognized in AOCI	38	-	38
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet			
Electric Generation, Transmission and Distribution Revenues	(233)	-	(233)
Purchased Electricity for Resale	428	-	428
Interest Expense	-	16	16
Ending Balance in AOCI as of March 31, 2009	$ 817	$ (509)	$ 308

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheet at March 31, 2009 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ 1,372	$ -	$ 1,372
Hedging Liabilities (a)	(117)	-	(117)
AOCI Gain (Loss) Net of Tax	817	(509)	308
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	791	(60)	731

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's Condensed Consolidated Balance Sheet.

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, 2009, the maximum length of time that KPCo is hedging (with SFAS 133 designated contracts) exposure to variability in future cash flows related to forecasted transactions is 14 months.

Credit Risk

Management limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. KPCo uses Moody's, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

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

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), KPCo is obligated to post an 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, the risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management believes that a downgrade below investment grade is unlikely. As of March 31, 2009, the aggregate value of such contracts was $7.8 million and KPCo was not required to post any collateral. KPCo would have been required to post $7.8 million of collateral at March 31, 2009, if certain credit ratings had declined below investment grade of which $7.7 million was attributable to RTO and ISO activities.

FAIR VALUE MEASUREMENTS

SFAS 157 Fair Value Measurements

As described in KPCo's 2008 Annual Report, SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The Derivatives, Hedging and Fair Value Measurements note within KPCo's 2008 Annual Report should be read in conjunction with this report.

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, 2009 and December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of March 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,671	$ 178,812	$ 3,296	$ (161,982)	$ 23,797
Cash Flow and Fair Value Hedges (a)	-	1,745	-	(373)	1,372
Dedesignated Risk Management Contracts (b)	-	-	-	2,456	2,456
Total Risk Management Assets	$ 3,671	$ 180,557	$ 3,296	$ (159,899)	$ 27,625
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,046	$ 171,880	$ 905	$ (164,196)	$ 12,635
Cash Flow and Fair Value Hedges (a)	-	490	-	(373)	117
DETM Assignment (c)	-	-	-	912	912
Total Risk Management Liabilities	$ 4,046	$ 172,370	$ 905	$ (163,657)	$ 13,664

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
			(in thousands)		
Assets:					
Risk Management Assets					
Risk Management Contracts (a)	$ 3,443	$ 140,387	$ 2,561	$ (125,636)	$ 20,755
Cash Flow and Fair Value Hedges (a)	-	1,418	-	(302)	1,116
Dedesignated Risk Management Contracts (b)	-	-	-	2,749	2,749
Total Risk Management Assets	$ 3,443	$ 141,805	$ 2,561	$ (123,189)	$ 24,620
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,021	$ 132,087	$ 848	$ (126,370)	$ 10,586
Cash Flow and Fair Value Hedges (a)	-	544	-	(302)	242
DETM Assignment (c)	-	-	-	1,118	1,118
Total Risk Management Liabilities	$ 4,021	$ 132,631	$ 848	$ (125,554)	$ 11,946

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 12 in KPCo's 2008 Annual Report.

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

Three Months Ended March 31, 2009	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of January 1, 2009	$ 1,713
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(834)
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	-
Transfers in and/or out of Level 3 (b)	(16)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,528
Balance as of March 31, 2009	$ 2,391

Three Months Ended March 31, 2008		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of January 1, 2008	$	(157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)		(131)
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		-
Transfers in and/or out of Level 3 (b)		(210)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		293
Balance as of March 31, 2008	$	(205)

(a) Included in revenues on KPCo's Condensed Statements of Income.

(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on KPCo's Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

8. INCOME TAXES

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

9. FINANCING ACTIVITIES

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of March 31, 2009 and December 31, 2008 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2009 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, 2009	Authorized Short-Term Borrowing Limit
(in thousands)					
$ 161,838	$ -	$ 145,160	$ -	$ 157,290	$ 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, 2009 and 2008 are summarized in the following table:

	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates For Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2009	2.28%	1.22%	-%	-%	1.69%	-%
2008	5.37%	3.39%	-%	-%	4.09%	-%

Credit Facilities

KPCo and certain other companies in the AEP System have a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of March 31, 2009, there were no outstanding amounts for KPCo under either facility. In April 2009, the $350 million 364-day credit agreement expired.

Kentucky Power Company

2009 Second Quarter Report

Financial Statements

AEP AMERICAN® ELECTRIC POWER

TABLE OF CONTENTS	Page

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.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
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.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APB	Accounting Principles Board Opinion.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
FSP	FASB Staff Position.
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.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MWH	Megawatthour.
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.

Term	Meaning
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	Public Utility Commission of Texas.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SIA	System Integration Agreement.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	Three Months Ended 2009	Three Months Ended 2008	Six Months Ended 2009	Six Months Ended 2008
REVENUES				
Electric Generation, Transmission and Distribution	$ 134,754	$ 128,152	$ 296,003	$ 275,211
Sales to AEP Affiliates	20,173	18,729	35,596	38,782
Other Revenues	172	170	1,933	348
TOTAL REVENUES	155,099	147,051	333,532	314,341
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	47,877	14,262	100,918	63,473
Purchased Electricity for Resale	5,735	5,706	14,352	9,472
Purchased Electricity from AEP Affiliates	48,852	60,262	97,038	114,452
Other Operation	12,301	13,877	24,339	29,385
Maintenance	5,582	16,603	26,927	26,523
Depreciation and Amortization	12,971	11,941	25,778	23,899
Taxes Other Than Income Taxes	3,637	2,872	5,983	4,052
TOTAL EXPENSES	136,955	125,523	295,335	271,256
OPERATING INCOME	18,144	21,528	38,197	43,085
Other Income (Expense):				
Other Income	62	886	90	2,518
Interest Expense	(7,423)	(7,496)	(14,733)	(14,351)
INCOME BEFORE INCOME TAX EXPENSE	10,783	14,918	23,554	31,252
Income Tax Expense	4,575	3,988	7,892	9,178
NET INCOME	$ 6,208	$ 10,930	$ 15,662	$ 22,074

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

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(5,000)		(5,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					381,604
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,796				(3,336)	(3,336)
NET INCOME			22,074		22,074
TOTAL COMPREHENSIVE INCOME					18,738
TOTAL COMMMON SHAREHOLDER'S EQUITY – JUNE 30, 2008	$ 50,450	$ 208,750	$ 145,292	$ (4,150)	$ 400,342
TOTAL COMMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 50,450	$ 208,750	$ 138,749	$ 59	$ 398,008
Capital Contribution from Parent		30,000			30,000
Common Stock Dividends			(13,500)		(13,500)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					414,508
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $40				(74)	(74)
NET INCOME			15,662		15,662
TOTAL COMPREHENSIVE INCOME					15,588
TOTAL COMMMON SHAREHOLDER'S EQUITY – JUNE 30, 2009	$ 50,450	$ 238,750	$ 140,911	$ (15)	$ 430,096

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 431	$ 646
Accounts Receivable:		
Customers	21,932	21,681
Affiliated Companies	5,423	6,721
Accrued Unbilled Revenues	1,444	2,533
Miscellaneous	89	83
Allowance for Uncollectible Accounts	(1,161)	(1,144)
Total Accounts Receivable	27,727	29,874
Fuel	32,503	29,440
Materials and Supplies	11,528	10,630
Risk Management Assets	16,808	13,760
Regulatory Asset for Under-Recovered Fuel Costs	4,140	9,953
Margin Deposits	8,997	5,207
Prepayments and Other Current Assets	6,654	5,751
TOTAL CURRENT ASSETS	108,788	105,261
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	543,940	533,998
Transmission	435,347	431,835
Distribution	550,514	528,711
Other Property, Plant and Equipment	63,972	65,485
Construction Work in Progress	32,705	46,650
Total Property, Plant and Equipment	1,626,478	1,606,679
Accumulated Depreciation and Amortization	496,381	476,568
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,130,097	1,130,111
OTHER NONCURRENT ASSETS		
Regulatory Assets	180,411	179,845
Long-term Risk Management Assets	11,681	10,860
Deferred Charges and Other Noncurrent Assets	37,615	41,884
TOTAL OTHER NONCURRENT ASSETS	229,707	232,589
TOTAL ASSETS	$ 1,468,592	$ 1,467,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 6,050	$ 131,399
Accounts Payable:		
General	31,052	35,584
Affiliated Companies	18,086	45,245
Risk Management Liabilities	7,156	6,316
Customer Deposits	17,464	15,985
Accrued Taxes	9,560	11,903
Accrued Interest	6,994	7,009
Other Current Liabilities	19,877	22,517
TOTAL CURRENT LIABILITIES	116,239	275,958
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	528,638	398,555
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	4,610	5,630
Deferred Income Taxes	266,746	259,666
Regulatory Liabilities and Deferred Investment Tax Credits	38,387	46,135
Employee Benefits and Pension Obligations	51,183	51,819
Deferred Credits and Other Noncurrent Liabilities	12,693	12,190
TOTAL NONCURRENT LIABILITIES	922,257	793,995
TOTAL LIABILITIES	1,038,496	1,069,953
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	208,750
Retained Earnings	140,911	138,749
Accumulated Other Comprehensive Income (Loss)	(15)	59
TOTAL COMMON SHAREHOLDER'S EQUITY	430,096	398,008
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,468,592	$ 1,467,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 15,662	$ 22,074
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	25,778	23,899
Deferred Income Taxes	12,112	7,866
Mark-to-Market of Risk Management Contracts	(4,395)	3,309
Change in Other Noncurrent Assets	4,379	(2,783)
Change in Other Noncurrent Liabilities	265	(1,599)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	2,147	6,041
Fuel, Materials and Supplies	(3,961)	(2,962)
Accounts Payable	(24,585)	1,462
Accrued Taxes, Net	(6,016)	(5,369)
Fuel Over/Under-Recovery, Net	5,813	(8,187)
Other Current Assets	(4,739)	(3,150)
Other Current Liabilities	(4,783)	(3,373)
Net Cash Flows from Operating Activities	17,677	37,228
INVESTING ACTIVITIES		
Construction Expenditures	(38,366)	(61,434)
Acquisitions of Assets	(269)	-
Proceeds from Sales of Assets	610	202
Net Cash Flows Used for Investing Activities	(38,025)	(61,232)
FINANCING ACTIVITIES		
Capital Contribution from Parent	30,000	-
Issuance of Long-term Debt – Nonaffiliated	129,292	-
Change in Advances from Affiliates, Net	(125,349)	29,282
Principal Payments for Capital Lease Obligations	(351)	(405)
Dividends Paid on Common Stock	(13,500)	(5,000)
Other Financing Activities	41	-
Net Cash Flows from Financing Activities	20,133	23,877
Net Decrease in Cash and Cash Equivalents	(215)	(127)
Cash and Cash Equivalents at Beginning of Period	646	727
Cash and Cash Equivalents at End of Period	$ 431	$ 600
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 20,048	$ 14,536
Net Cash Paid for Income Taxes	541	603
Noncash Acquisitions Under Capital Leases	586	126
Construction Expenditures Included in Accounts Payable at June 30,	2,556	6,648

See Condensed Notes to Condensed Financial Statements.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Derivatives and Hedging
8. Fair Value Measurements
9. Income Taxes
10. Financing Activities

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and six months ended June 30, 2009 are not necessarily indicative of results that may be expected for the year ending December 31, 2009. Management reviewed subsequent events through the August 4, 2009 issuance date of KPCo's second quarter financial statements and footnotes. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2008 financial statements and notes thereto, which are included in KPCo's 2008 Annual Report.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. 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 and other factors. Management believes that the significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

KPCo holds a significant variable interest in AEPSC and AEGCo. AEPSC provides certain managerial and professional services to KPCo. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo and other AEP subsidiaries at AEPSC's cost. KPCo and other AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and KPCo and other AEP subsidiaries that could require additional financial support from KPCo and other AEP subsidiaries or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo and other AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. KPCo is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. 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. Total billings from AEPSC for the three months ended June 30, 2009 and 2008 were $9 million and $13 million, respectively, and for the six months ended June 30, 2009 and 2008 were $17 million and $23 million, respectively. The carrying amount of liabilities associated with AEPSC as of June 30, 2009 and December 31, 2008 were $3 million and $5 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, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. KPCo has no involvement with AEGCo's interest in the Lawrenceburg Generating Station. 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 the nature of the AEP Power Pool, there is a sharing of the cost of Rockport Plant such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport Plant. 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, 2009 and 2008 were $26 million and $24 million, respectively, and for the six months ended

June 30, 2009 and 2008 were $53 million and $50 million, respectively. The carrying amount of liabilities associated with AEGCo as of June 30, 2009 and December 31, 2008 were $9 million in both periods. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Revenue Recognition – Traditional Electricity Supply and Demand

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on its Condensed Statements of Income upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies then purchase power from PJM to supply their customers. Generally, these power sales and purchases are reported on a net basis as revenues on KPCo's Condensed Statements of Income. However, in 2009, there were times when the AEP East companies were purchasers of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale on KPCo's Condensed Statements of Income.

Physical energy purchases, including those from RTOs, that are identified as non-trading, are accounted for on a gross basis in Purchased Electricity for Resale on KPCo's Condensed Statements of Income.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of new pronouncements issued or implemented in 2009 and standards issued but not implemented that management has determined relate to KPCo's operations.

Pronouncements Adopted During 2009

The following standards were effective during the first six months of 2009. Consequently, the financial statements and footnotes reflect their impact.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. KPCo does not have any such tax positions that result in adjustments.

In April 2009, the FASB issued FSP SFAS 141(R)-1 "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." The standard clarifies accounting and disclosure for contingencies arising in business combinations. It was effective January 1, 2009.

KPCo adopted SFAS 141R, including the FSP, effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. KPCo had no business combinations in 2009. KPCo will apply it to any future business combinations.

SFAS 160 "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

KPCo adopted SFAS 160 effective January 1, 2009 with no impact on its financial statements or footnote disclosures.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of the primary underlying risk and accounting designation.

KPCo adopted SFAS 161 effective January 1, 2009. This standard increased disclosures related to derivative instruments and hedging activities. See Note 7.

SFAS 165 "Subsequent Events" (SFAS 165)

In May 2009, the FASB issued SFAS 165 incorporating guidance on subsequent events into authoritative accounting literature and clarifying the time following the balance sheet date which management reviewed for events and transactions that may require disclosure in the financial statements.

KPCo adopted this standard effective second quarter of 2009. The standard increased disclosure by requiring disclosure of the date through which subsequent events have been reviewed. The standard did not change management's procedures for reviewing subsequent events.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

KPCo adopted EITF 08-5 effective January 1, 2009. With the adoption of FSP SFAS 107-1 and APB 28-1, it is applied to the fair value of long-term debt. The application of this standard had an immaterial effect on the fair value of debt outstanding.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

KPCo adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments" (FSP SFAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments.

KPCo adopted the standard effective second quarter of 2009. This standard increased the disclosure requirements related to financial instruments. See "Fair Value Measurements of Long-term Debt" section of Note 8.

FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP SFAS 115-2 and SFAS 124-2)

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2 amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements.

KPCo adopted the standard effective second quarter of 2009 with no impact on its financial statements or disclosures.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

KPCo adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2)

In February 2008, the FASB issued SFAS 157-2 which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. 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.

KPCo adopted SFAS 157-2 effective January 1, 2009. KPCo will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analyses related to long-lived assets, equity investments, goodwill and intangibles. KPCo did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first six months of 2009.

FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4)

In April 2009, the FASB issued FSP SFAS 157-4 providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods.

KPCo adopted the standard effective second quarter of 2009. The standard had no impact on the financial statements but increased disclosure requirements. See "Fair Value Measurements of Financial Assets and Liabilities" section of Note 8.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts will be disclosed at that time.

SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166)

In June 2009, the FASB issued SFAS 166 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

SFAS 166 is effective for interim and annual reporting in fiscal years beginning after November 15, 2009. Early adoption is prohibited. Although management has not completed an analysis, management does not expect this standard to have a material impact on the financial statements. KPCo will adopt SFAS 166 effective January 1, 2010.

SFAS 167 "Amendments to FASB Interpretation No. 46(R)" (SFAS 167)

In June 2009, the FASB issued SFAS 167 amending the analysis an entity must perform to determine if it has a controlling interest in a variable interest entity (VIE). This new guidance provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE's economic performance.
- The obligation to absorb the losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

The standard also requires separate presentation on the face of the statement of financial position for assets which can only be used to settle obligations of a consolidated VIE and liabilities for which creditors do not have recourse to the general credit of the primary beneficiary.

SFAS 167 is effective for interim and annual reporting in fiscal years beginning after November 15, 2009. Early adoption is prohibited. Management continues to review the impact of the changes in the consolidation guidance on the financial statements. This standard will increase disclosure requirements related to transactions with VIEs and change the presentation of consolidated VIE's assets and liabilities on KPCo's balance sheets. KPCo will adopt SFAS 167 effective January 1, 2010.

SFAS 168 "The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles" (SFAS 168)

In June 2009, the FASB issued SFAS 168 establishing the FASB Accounting Standards Codification™ as the authoritative source of accounting principles for preparation of financial statements and reporting in conformity with GAAP by nongovernmental entities.

This standard is effective for interim and annual reporting periods ending after September 15, 2009. It requires an update of all references to authoritative accounting literature. KPCo will adopt SFAS 168 effective third quarter of 2009.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policies including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. KPCo will adopt the standard effective for the 2009 Annual Report.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, leases, insurance, hedge accounting, discontinued operations and income tax. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

3. RATE MATTERS

As discussed in KPCo's 2008 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2008 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 2009 and updates KPCo's 2008 Annual Report.

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis, these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that the KPSC has the authority to provide for surcharges and surcredits until the court of appeals rules otherwise.

In November 2008, the Kentucky Court of Appeals concluded that Duke Energy's surcharge was illegal. However, the order stated that the "decision was premised on the nature of the long-term capital improvements proposed by Duke Energy as distinguished from the fuel and other surcharges that are fluctuating and unanticipated. The latter have been approved by the Kentucky Supreme Court and remain the law." In February 2009, the Kentucky Court of Appeals denied the KPSC request for appeal of the Franklin County Circuit Court decision. In March 2009, the KPSC filed for a discretionary review of the related Duke Energy case with the Kentucky Supreme Court. Management believes that all of KPCo's variable rate mechanisms are valid and would be upheld if ever challenged.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. KPCo's portion of recognized gross SECA revenues was $17 million.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers are engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion of any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. KPCo provided reserves of 2.9 million and $400 thousand in 2006 and 2007, respectively.

In February 2009, a settlement agreement was approved by the FERC resulting in the completion of a $1 million settlement applicable to $20 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $10 million applicable to $112 million of SECA revenues. The balance in the reserve for future settlements as of June 30, 2009 was $34 million. KPCo's reserve balance at June 30, 2009 was $2.6 million. As of June 30, 2009, there were no in-process settlements.

Management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. If the remaining unsettled SECA claims are settled for considerably more than the to-date settlements or if the remaining unsettled claims cannot be settled and are awarded a refund by the FERC greater than the remaining reserve balance, it could have an adverse effect on net income. Cash flows will be adversely impacted by any additional settlements or ordered refunds.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain state regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this review will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. The AEP East companies sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. In January and March 2009, the AEP East companies received retail rate increases in Tennessee and Indiana, respectively, that recognized the higher retail transmission costs resulting from the loss of wholesale transmission revenues from T&O transactions. As a result, the AEP East companies are now recovering approximately 98% of the lost T&O transmission revenues. The remaining 2% is being incurred by I&M until it can revise its rates in Michigan to recover the lost revenues.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of the AEP East companies' transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings to reflect the resultant additional transmission cost reductions. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, established a settlement proceeding with an ALJ, and delayed the requested October 2008 effective date for five months. The requested increase, which the AEP East companies began billing in April 2009 for service as of March 1, 2009, will produce a $63 million annualized increase in revenues. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies' transmission facilities so that retail rates for jurisdictions other than Ohio are not directly affected. In October 2008, AEP filed the required compliance filing, and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing.

In May 2009, the first annual update of the formula rate was filed with the FERC which reflected increased transmission service revenue requirements of approximately $32 million on an annualized basis, effective for service as of July 1, 2009 to be billed in August 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM. Retail rates for other AEP East jurisdictions are not directly affected.

Under the formula, the second annual update will be filed effective July 1, 2010 and each year thereafter. Also, beginning with the July 1, 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. Following authorized regulatory treatment, the AEP West companies shared a portion of SIA margins with their wholesale and retail customers during the period June 2000 to March 2006. In December 2008, the AEP West companies recorded a provision for refund reflecting the sharing. Management cannot predict the outcome of the requested FERC rehearing proceeding or any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding related future state regulatory proceedings is adequate.

Transmission Agreement (TA)

Certain transmission equipment placed in service in 1998 in KPCo's service territory was inadvertently excluded from the AEP East companies' TA calculation. As a result, KPCo did not receive a TA credit for this equipment from the other TA member companies. The amount involved was $7 million annually. It was not discovered until February 2009. KPCo's base electric rates were adjusted only once, in April 2006, during the period in which the error was in effect. Effective January 2009, the allocation was revised to give KPCo its full TA credit prospectively and the KPSC staff and attending intervenors were informed about the revision at a meeting in April 2009. Management does not believe that it is probable that a material retroactive rate adjustment will result.

Modification of the Transmission Agreement (TA)

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA entered into in 1984, as amended, that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations operated at 345kV and above. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, WPCo and KGPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse the majority of PJM transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. Management is unable to predict the outcome of this proceeding and the effect, if any, it will have on future net income and cash flows due to timing of implementation by various state regulators.

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 adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2008 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to June 30, 2009, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, KPCo will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into replacement leasing arrangements for the equipment affected by this notification prior to the termination date of 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At June 30, 2009, the maximum potential loss for these lease agreements was approximately $262 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

CONTINGENCIES

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. Management asserted claims against certain companies that sold power to KPCo and other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities. Management is unable to predict the outcome of these proceedings or their impact on future net income and cash flows.

5. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and six months ended June 30, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 11	$ 11
Interest Cost	64	62	28	28
Expected Return on Plan Assets	(81)	(84)	(20)	(28)
Amortization of Transition Obligation	-	-	6	7
Amortization of Net Actuarial Loss	15	10	10	2
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 20

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 52	$ 50	$ 21	$ 21
Interest Cost	127	125	55	56
Expected Return on Plan Assets	(161)	(168)	(40)	(56)
Amortization of Transition Obligation	-	-	13	14
Amortization of Net Actuarial Loss	30	19	21	5
Net Periodic Benefit Cost	$ 48	$ 26	$ 70	$ 40

The following table provides KPCo's net periodic benefit cost for the plans for the three and six months ended June 30, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	2009	2008	2009	2008
	(in thousands)			
Three Months Ended June 30,	$ 554	$ 249	$ 808	$ 400
Six Months Ended June 30,	1,109	498	1,616	801

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

Strategies for Utilization of Derivative Instruments to Achieve Objectives

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal SFAS 133 hedging strategies. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under SFAS 133. Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of SFAS 133.

AEPSC, on behalf of KPCo, enters into electricity, coal, natural gas, interest rate and to a lesser degree heating oil, 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. 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 June 30, 2009:

Notional Volume of Derivative Instruments
June 30, 2009

Primary Risk Exposure	Volume		Unit of Measure
	(in thousands)		
Commodity:			
Power		37,454	MWHs
Coal		3,091	Tons
Natural Gas		6,605	MMBtus
Heating Oil and Gasoline		390	Gallons
Interest Rate	$	8,469	USD
Interest Rate	$	-	USD

Fair Value Hedging Strategies

At certain times, AEPSC, on behalf of KPCo, enters into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These 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. During 2009 and 2008, this strategy was not actively employed.

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 electricity, coal and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. KPCo 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. During 2009 and 2008, KPCo designated cash flow hedging relationships using these commodities.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial gasoline and heating oil derivative contracts in order mitigate price risk of future fuel purchases. KPCo does not hedge all of fuel price risk. During 2009, KPCo designated cash flow hedging strategies of forecasted fuel purchases. This strategy was not active for KPCo during 2008. For disclosure purposes, these contracts are included with other hedging activity as "Commodity."

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated 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. During 2009 and 2008, KPCo did not have any active interest rate cash flow hedge strategies.

Accounting for Derivative Instruments and the Impact on KPCo's Financial Statements

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the balance sheet 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 FSP FIN 39-1, 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, 2009 and December 31, 2008 balance sheets, KPCo netted $2.2 million and $468 thousand of cash collateral received from third parties against short-term and long-term risk management assets, respectively, and $6.7 million and $1.2 million of cash collateral paid to third parties against short-term and long-term risk management liabilities, respectively.

The following table represents the gross fair value impact of KPCo's derivative activity on the Condensed Balance Sheet as of June 30, 2009.

Fair Value of Derivative Instruments
June 30, 2009
(in thousands)

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate**	**Other (b)**	**Total**
Current Risk Management Assets	$ 128,004	$ 1,407	$ -	$ (112,603)	$ 16,808
Long-term Risk Management Assets	45,053	372	-	(33,744)	11,681
Total Assets	173,057	1,779	-	(146,347)	28,489
Current Risk Management Liabilities	121,892	901	-	(115,637)	7,156
Long-term Risk Management Liabilities	40,816	349	-	(36,555)	4,610
Total Liabilities	162,708	1,250	-	(152,192)	11,766
Total MTM Derivative Contract Net Assets (Liabilities)	$ 10,349	$ 529	$ -	$ 5,845	$ 16,723

(a) Derivative instruments within these categories are reported gross. These instruments are subject to master netting agreements and are presented in the Condensed Balance Sheets on a net basis in accordance with FIN 39 "Offsetting of Amounts Related to Certain Contracts."

(b) Amounts represent counterparty netting of risk management contracts, associated cash collateral in accordance with FSP FIN 39-1 and dedesignated risk management contracts.

The table below presents KPCo's MTM activity of derivative risk management contracts for the three and six months ended June 30, 2009:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 3,726	$ 11,775
Sales to AEP Affiliates	(247)	(1,773)
Regulatory Assets	-	-
Regulatory Liabilities	1,252	619
Total Gain on Risk Management Contracts	$ 4,731	$ 10,621

Certain qualifying derivative instruments have been designated as normal purchase or normal sale contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in 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, KPCo 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. Realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in KPCo's Condensed Statements of Income. 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. Unrealized and 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 SFAS 71.

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), KPCo recognizes 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 in Net Income during the period of change.

KPCo records realized 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, 2009 and 2008, this strategy was not actively employed.

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) in accordance with SFAS 71.

Realized gains and losses on derivatives transactions for the purchase and sale of electricity, 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 in KPCo's Condensed Statements of Income, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to commodities. During the three and six months ended June 30, 2009 and 2008, KPCo recognized immaterial amounts in Net Income related to hedge ineffectiveness.

Beginning in 2009, KPCo executed financial heating oil and gasoline derivative contracts to hedge the price risk of its diesel fuel and gasoline purchased. KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Other Operation and Maintenance Expense or Depreciation and Amortization Expense, as it relates to capital projects, on the Condensed Statements of Income. KPCo does not hedge all fuel price exposure. During the three and six months ended June 30, 2009, KPCo recognized no hedge ineffectiveness related to this hedge strategy.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and six months ended June 30, 2009 and 2008, this strategy was not actively employed.

The following tables provide details on designated, effective cash flow hedges included in AOCI on KPCo's Condensed Balance Sheets and the reasons for changes in cash flow hedges for the three and six months ended June 30, 2009. 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 June 30, 2009
(in thousands)

	Commodity	Interest Rate	Total
Beginning Balance in AOCI as of April 1, 2009	$ 817	$ (509)	$ 308
Changes in Fair Value Recognized in AOCI	(24)	-	(24)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheets:			
Electric Generation, Transmission and Distribution Revenues	(440)	-	(440)
Fuel and Other Consumables Used for Electric Generation	(1)	-	(1)
Purchased Electricity for Resale	127	-	127
Interest Expense	-	16	16
Property, Plant and Equipment	(1)	-	(1)
Ending Balance in AOCI as of June 30, 2009	$ 478	$ (493)	$ (15)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Six Months Ended June 30, 2009
(in thousands)

	Commodity	Interest Rate	Total
Beginning Balance in AOCI as of January 1, 2009	$ 584	$ (525)	$ 59
Changes in Fair Value Recognized in AOCI	14	-	14
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheets:			
Electric Generation, Transmission and Distribution Revenues	(673)	-	(673)
Fuel and Other Consumables Used for Electric Generation	(1)	-	(1)
Purchased Electricity for Resale	555	-	555
Interest Expense	-	32	32
Property, Plant and Equipment	(1)	-	(1)
Ending Balance in AOCI as of June 30, 2009	$ 478	$ (493)	$ (15)

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheet at June 30, 2009 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
June 30, 2009

	Commodity	Interest Rate (in thousands)	Total
Hedging Assets (a)	$ 1,002	$ -	$ 1,002
Hedging Liabilities (a)	(473)	-	(473)
AOCI Gain (Loss) Net of Tax	478	(493)	(15)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	463	(60)	403

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's Condensed Balance Sheet.

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, 2009, the maximum length of time that KPCo is hedging (with SFAS 133 designated contracts) exposure to variability in future cash flows related to forecasted transactions is 20 months.

Credit Risk

Management limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. KPCo uses Moody's, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

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

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), KPCo is obligated to post an 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, the risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management believes that a downgrade below investment grade is unlikely. As of June 30, 2009, the aggregate value of such contracts was $3.2 million and KPCo was not required to post any collateral. KPCo would have been required to post $3.2 million of collateral at June 30, 2009 if certain credit ratings had declined below investment grade of which $3 million was attributable to RTO and ISO activities.

8. FAIR VALUE MEASUREMENTS

With the adoption of two new accounting standards, KPCo is required to provide certain fair value disclosures which were previously only required in the annual report. The new standards did not change the method to calculate the amounts reported on KPCo's Condensed Balance Sheets.

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. 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 at June 30, 2009 and December 31, 2008 are summarized in the following table:

	June 30, 2009		December 31, 2008	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 548,638	$ 550,198	$ 418,555	$ 366,108

Fair Value Measurements of Financial Assets and Liabilities

As described in KPCo's 2008 Annual Report, SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The Derivatives, Hedging and Fair Value Measurements note within KPCo's 2008 Annual Report should be read in conjunction with this report.

Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within 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. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in 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 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, 2009 and December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 2,420	$ 165,425	$ 4,458	$ (147,019)	$ 25,284
Cash Flow and Fair Value Hedges (a)	-	1,765	-	(763)	1,002
Dedesignated Risk Management Contracts (b)	-	-	-	2,203	2,203
Total Risk Management Assets	$ 2,420	$ 167,190	$ 4,458	$ (145,579)	$ 28,489
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 2,638	$ 157,660	$ 1,657	$ (151,461)	$ 10,494
Cash Flow and Fair Value Hedges (a)	-	1,236	-	(763)	473
DETM Assignment (c)	-	-	-	799	799
Total Risk Management Liabilities	$ 2,638	$ 158,896	$ 1,657	$ (151,425)	$ 11,766

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,443	$ 140,387	$ 2,561	$ (125,636)	$ 20,755
Cash Flow and Fair Value Hedges (a)	-	1,418	-	(302)	1,116
Dedesignated Risk Management Contracts (b)	-	-	-	2,749	2,749
Total Risk Management Assets	$ 3,443	$ 141,805	$ 2,561	$ (123,189)	$ 24,620
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,021	$ 132,087	$ 848	$ (126,370)	$ 10,586
Cash Flow and Fair Value Hedges (a)	-	544	-	(302)	242
DETM Assignment (c)	-	-	-	1,118	1,118
Total Risk Management Liabilities	$ 4,021	$ 132,631	$ 848	$ (125,554)	$ 11,946

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 12 in KPCo's 2008 Annual Report.

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

Three Months Ended June 30, 2009		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of April 1, 2009	$	2,391
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)		(955)
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		-
Transfers in and/or out of Level 3 (b)		(487)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		1,852
Balance as of June 30, 2009	$	2,801

Six Months Ended June 30, 2009		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of January 1, 2009	$	1,713
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)		(1,326)
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		-
Transfers in and/or out of Level 3 (b)		(46)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		2,460
Balance as of June 30, 2009	$	2,801

Three Months Ended June 30, 2008		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of April 1, 2008	$	(205)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)		(112)
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		-
Transfers in and/or out of Level 3 (b)		(467)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(3,186)
Balance as of June 30, 2008	$	(3,970)

Six Months Ended June 30, 2008		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of January 1, 2008	$	(157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)		(89)
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		-
Transfers in and/or out of Level 3 (b)		(13)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(3,711)
Balance as of June 30, 2008	$	(3,970)

(a) Included in revenues on KPCo's Condensed Statements of Income.

(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on KPCo's Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

9. INCOME TAXES

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

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

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

Federal Tax Legislation

The American Recovery and Reinvestment Act of 2009 was signed into law by the President in February 2009. It 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 are not expected to have a material impact on net income or financial condition. However, management forecasts the bonus depreciation provision could provide a significant favorable cash flow benefit in 2009.

10. FINANCING ACTIVITIES

Long-term Debt

Long-term debt issued during the first six months of 2009 were:

	Type of Debt	Principal Amount	Interest Rate	Due Date
		(in thousands)		
Issuances:	Senior Unsecured Notes	$ 40,000	7.25%	2021
	Senior Unsecured Notes	30,000	8.03%	2029
	Senior Unsecured Notes	60,000	8.13%	2039

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of June 30, 2009 and December 31, 2008 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the six months ended June 30, 2009 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 June 30, 2009	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 174,108	$ -	$ 143,657	$ -	$ 6,050	$ 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, 2009 and 2008 are summarized in the following table:

	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates For Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2009	2.28%	0.65%	-%	-%	1.33%	-%
2008	5.37%	2.91%	-%	-%	3.39%	-%

Credit Facilities

KPCo and certain other companies in the AEP System have a $627 million 3-year credit agreement. Under the facility, letters of credit may be issued. As of June 30, 2009, there were no outstanding amounts for KPCo under this credit facility. KPCo and certain other companies in the AEP System had a $350 million 364-day credit agreement that expired in April 2009.

Kentucky Power Company

2009 Third Quarter Report

Financial Statements

TABLE OF CONTENTS	Page

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.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
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.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APB	Accounting Principles Board Opinion.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
ASU	Accounting Standards Update issued by the Financial Accounting Standards Board.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FSP	FASB Staff Position.
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.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MMBtu	Million British Thermal Units.
MTM	Mark-to-Market.
MWH	Megawatthour.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.

Term	Meaning
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	Public Utility Commission of Texas.
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.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SIA	System Integration Agreement.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2009 and 2008
(in thousands)
(Unaudited)

	Three Months Ended		Nine Months Ended	
	2009	2008	2009	2008
REVENUES				
Electric Generation, Transmission and Distribution	$ 139,868	$ 171,257	$ 435,871	$ 446,468
Sales to AEP Affiliates	11,973	17,457	47,569	56,239
Other Revenues	312	158	2,245	506
TOTAL REVENUES	152,153	188,872	485,685	503,213
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	42,330	52,723	143,248	116,196
Purchased Electricity for Resale	5,498	10,034	19,850	19,506
Purchased Electricity from AEP Affiliates	53,258	63,469	150,296	177,921
Other Operation	12,655	20,524	36,994	49,909
Maintenance	11,561	10,389	38,488	36,912
Depreciation and Amortization	13,100	11,996	38,878	35,895
Taxes Other Than Income Taxes	2,828	2,967	8,811	7,019
TOTAL EXPENSES	141,230	172,102	436,565	443,358
OPERATING INCOME	10,923	16,770	49,120	59,855
Other Income (Expense):				
Interest Income	53	209	165	2,050
Allowance for Equity Funds Used During Construction	159	251	137	928
Interest Expense	(9,109)	(7,058)	(23,842)	(21,409)
INCOME BEFORE INCOME TAX EXPENSE	2,026	10,172	25,580	41,424
Income Tax Expense	717	2,721	8,609	11,899
NET INCOME	$ 1,309	$ 7,451	$ 16,971	$ 29,525

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

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2009 and 2008
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(7,500)		(7,500)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					379,104
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $236				439	439
NET INCOME			29,525		29,525
TOTAL COMPREHENSIVE INCOME					29,964
TOTAL COMMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2008	$ 50,450	$ 208,750	$ 150,243	$ (375)	$ 409,068
TOTAL COMMMON SHAREHOLDER'S EQUITY – DECEMBER 31, 2008	$ 50,450	$ 208,750	$ 138,749	$ 59	$ 398,008
Capital Contribution from Parent		30,000			30,000
Common Stock Dividends			(13,500)		(13,500)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					414,508
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $235				(437)	(437)
NET INCOME			16,971		16,971
TOTAL COMPREHENSIVE INCOME					16,534
TOTAL COMMON SHAREHOLDER'S EQUITY – SEPTEMBER 30, 2009	$ 50,450	$ 238,750	$ 142,220	$ (378)	$ 431,042

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2009 and December 31, 2008
(in thousands)
(Unaudited)

	2009	2008
CURRENT ASSETS		
Cash and Cash Equivalents	$ 545	$ 646
Advances to Affiliates	4,197	-
Accounts Receivable:		
Customers	15,189	24,214
Affiliated Companies	12,798	6,721
Miscellaneous	98	83
Allowance for Uncollectible Accounts	(863)	(1,144)
Total Accounts Receivable	27,222	29,874
Fuel	43,335	29,440
Materials and Supplies	11,555	10,630
Risk Management Assets	17,157	13,760
Regulatory Asset for Under-Recovered Fuel Costs	-	9,953
Margin Deposits	6,830	5,207
Prepayments and Other Current Assets	6,831	5,751
TOTAL CURRENT ASSETS	117,672	105,261
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	546,261	533,998
Transmission	436,133	431,835
Distribution	559,287	528,711
Other Property, Plant and Equipment	64,119	65,485
Construction Work in Progress	28,208	46,650
Total Property, Plant and Equipment	1,634,008	1,606,679
Accumulated Depreciation and Amortization	504,570	476,568
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,129,438	1,130,111
OTHER NONCURRENT ASSETS		
Regulatory Assets	180,332	179,845
Long-term Risk Management Assets	11,693	10,860
Deferred Charges and Other Noncurrent Assets	35,008	41,884
TOTAL OTHER NONCURRENT ASSETS	227,033	232,589
TOTAL ASSETS	$ 1,474,143	$ 1,467,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
September 30, 2009 and December 31, 2008
(Unaudited)

	2009	2008
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 131,399
Accounts Payable:		
General	22,864	35,584
Affiliated Companies	21,643	45,245
Risk Management Liabilities	6,374	6,316
Customer Deposits	17,761	15,985
Accrued Taxes	9,272	11,903
Accrued Interest	6,217	7,009
Regulatory Liability for Over-Recovered Fuel Costs	4,820	-
Other Current Liabilities	17,236	22,517
TOTAL CURRENT LIABILITIES	106,187	275,958
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	528,680	398,555
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	4,789	5,630
Deferred Income Taxes	278,982	259,666
Regulatory Liabilities and Deferred Investment Tax Credits	40,499	46,135
Employee Benefits and Pension Obligations	50,983	51,819
Deferred Credits and Other Noncurrent Liabilities	12,981	12,190
TOTAL NONCURRENT LIABILITIES	936,914	793,995
TOTAL LIABILITIES	1,043,101	1,069,953
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	208,750
Retained Earnings	142,220	138,749
Accumulated Other Comprehensive Income (Loss)	(378)	59
TOTAL COMMON SHAREHOLDER'S EQUITY	431,042	398,008
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,474,143	$ 1,467,961

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2009 and 2008
(in thousands)
(Unaudited)

	2009	2008
OPERATING ACTIVITIES		
Net Income	$ 16,971	$ 29,525
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	38,878	35,895
Deferred Income Taxes	21,992	5,709
Allowance for Equity Funds Used During Construction	(137)	(928)
Mark-to-Market of Risk Management Contracts	(5,884)	1,494
Fuel Over/Under-Recovery, Net	14,773	(12,176)
Change in Other Noncurrent Assets	8,276	(987)
Change in Other Noncurrent Liabilities	1,365	(286)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	2,945	6,264
Fuel, Materials and Supplies	(14,820)	(9,200)
Accounts Payable	(29,494)	7,051
Accrued Taxes, Net	(6,139)	510
Other Current Assets	(2,934)	(3,466)
Other Current Liabilities	(6,376)	(6,632)
Net Cash Flows from Operating Activities	39,416	52,773
INVESTING ACTIVITIES		
Construction Expenditures	(49,734)	(91,457)
Changes in Advances to Affiliates, Net	(4,197)	-
Acquisitions of Assets	(297)	-
Proceeds from Sales of Assets	622	577
Net Cash Flows Used for Investing Activities	(53,606)	(90,880)
FINANCING ACTIVITIES		
Capital Contribution from Parent	30,000	-
Issuance of Long-term Debt – Nonaffiliated	129,292	-
Change in Advances from Affiliates, Net	(131,399)	45,939
Principal Payments for Capital Lease Obligations	(547)	(604)
Dividends Paid on Common Stock	(13,500)	(7,500)
Other Financing Activities	243	-
Net Cash Flows from Financing Activities	14,089	37,835
Net Decrease in Cash and Cash Equivalents	(101)	(272)
Cash and Cash Equivalents at Beginning of Period	646	727
Cash and Cash Equivalents at End of Period	$ 545	$ 455
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 29,776	$ 24,376
Net Cash Received for Income Taxes	(2,416)	(231)
Noncash Acquisitions Under Capital Leases	794	237
Construction Expenditures Included in Accounts Payable at September 30,	2,834	9,634

See Condensed Notes to Condensed Financial Statements.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Derivatives and Hedging
8. Fair Value Measurements
9. Income Taxes
10. Financing Activities

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. Net income for the three and nine months ended September 30, 2009 is not necessarily indicative of results that may be expected for the year ending December 31, 2009. Management reviewed subsequent events through the October 30, 2009 issuance date of KPCo's third quarter financial statements and footnotes. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2008 financial statements and notes thereto, which are included in KPCo's 2008 Annual Report.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they 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 and other factors. Management believes that the significant assumptions and judgments were applied consistently. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support to any VIE that was not previously contractually required.

KPCo holds a significant variable interest in AEPSC and AEGCo. AEPSC provides certain managerial and professional services to KPCo. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo and other AEP subsidiaries at AEPSC's cost. KPCo and other AEP subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and KPCo and other AEP subsidiaries that could require additional financial support from KPCo and other AEP subsidiaries or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo and other AEP subsidiaries are exposed to losses to the extent they cannot recover the costs of AEPSC through their normal business operations. KPCo is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. 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. Total billings from AEPSC for the three months ended September 30, 2009 and 2008 were $8 million and $11 million, respectively, and for the nine months ended September 30, 2009 and 2008 were $25 million and $34 million, respectively. The carrying amount of liabilities associated with AEPSC as of September 30, 2009 and December 31, 2008 were $3 million and $5 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, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. KPCo has no involvement with AEGCo's interest in the Lawrenceburg Generating Station. 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 the nature of the AEP Power Pool, there is a sharing of the cost of Rockport Plant such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport Plant. 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, 2009 and 2008 were $25 million and $28 million, respectively, and for the nine months ended September 30, 2009 and 2008 were $78 million in both periods. The carrying amount of liabilities associated with AEGCo as of September 30, 2009 and December 31, 2008 were $8 million and $9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

Revenue Recognition – Traditional Electricity Supply and Demand

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. KPCo recognizes the revenues on its Condensed Statements of Income upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply their customers. Generally, these power sales and purchases are reported on a net basis as revenues on the Condensed Statements of Income. However, in 2009, there were times when the AEP East companies were purchasers of power from PJM to serve retail load. These purchases were recorded gross as Purchased Electricity for Resale on the Condensed Statements of Income.

Physical energy purchases, including those from RTOs, that are identified as non-trading, are accounted for on a gross basis in Purchased Electricity for Resale on KPCo's Condensed Statements of Income.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of new pronouncements issued or implemented in 2009 and standards issued but not implemented that management has determined relate to KPCo's operations.

Pronouncements Adopted During 2009

The following standards were effective during the first nine months of 2009. Consequently, the financial statements and footnotes reflect their impact.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. KPCo does not have any such tax positions that result in adjustments.

In April 2009, the FASB issued FSP SFAS 141(R)-1 "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arise from Contingencies." The standard clarifies accounting and disclosure for contingencies arising in business combinations. It was effective January 1, 2009.

KPCo adopted SFAS 141R, including the FSP, effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. KPCo had no business combinations in 2009. KPCo will apply it to any future business combinations. SFAS 141R is included in the "Business Combination" accounting guidance.

SFAS 160 "Noncontrolling Interests in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

KPCo adopted SFAS 160 effective January 1, 2009 with no impact on its financial statements or footnote disclosures. SFAS 160 is included in the "Consolidation" accounting guidance.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of the primary underlying risk and accounting designation.

KPCo adopted SFAS 161 effective January 1, 2009. This standard increased disclosures related to derivative instruments and hedging activities. See Note 7. SFAS 161 is included in the "Derivatives and Hedging" accounting guidance.

SFAS 165 "Subsequent Events" (SFAS 165)

In May 2009, the FASB issued SFAS 165 incorporating guidance on subsequent events into authoritative accounting literature and clarifying the time following the balance sheet date which management reviewed for events and transactions that may require disclosure in the financial statements.

KPCo adopted this standard effective second quarter of 2009. The standard increased disclosure by requiring disclosure of the date through which subsequent events have been reviewed. The standard did not change management's procedures for reviewing subsequent events. SFAS 165 is included in the "Subsequent Events" accounting guidance.

SFAS 168 "The FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles" (SFAS 168)

In June 2009, the FASB issued SFAS 168 establishing the FASB Accounting Standards Codification™ as the authoritative source of accounting principles for preparation of financial statements and reporting in conformity with GAAP by nongovernmental entities.

KPCo adopted SFAS 168 effective third quarter of 2009. It required an update of all references to authoritative accounting literature. SFAS 168 is included in the "Generally Accepted Accounting Principles" accounting guidance.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

KPCo adopted EITF 08-5 effective January 1, 2009. With the adoption of FSP SFAS 107-1 and APB 28-1, it is applied to the fair value of long-term debt. The application of this standard had an immaterial effect on the fair value of debt outstanding. EITF 08-5 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

KPCo adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively. EITF 08-6 is included in the "Investments – Equity Method and Joint Ventures" accounting guidance.

FSP SFAS 107-1 and APB 28-1 "Interim Disclosures about Fair Value of Financial Instruments" (FSP SFAS 107-1 and APB 28-1)

In April 2009, the FASB issued FSP SFAS 107-1 and APB 28-1 requiring disclosure about the fair value of financial instruments in all interim reporting periods. The standard requires disclosure of the method and significant assumptions used to determine the fair value of financial instruments.

KPCo adopted the standard effective second quarter of 2009. This standard increased the disclosure requirements related to financial instruments. See "Fair Value Measurements of Long-term Debt" section of Note 8. FSP SFAS 107-1 and APB 28-1 is included in the "Financial Instruments" accounting guidance.

FSP SFAS 115-2 and SFAS 124-2 "Recognition and Presentation of Other-Than-Temporary Impairments" (FSP SFAS 115-2 and SFAS 124-2)

In April 2009, the FASB issued FSP SFAS 115-2 and SFAS 124-2 amending the other-than-temporary impairment (OTTI) recognition and measurement guidance for debt securities. For both debt and equity securities, the standard requires disclosure for each interim reporting period of information by security class similar to previous annual disclosure requirements.

KPCo adopted the standard effective second quarter of 2009 with no impact on its financial statements or disclosures. FSP SFAS 115-2 and SFAS 124-2 is included in the "Investments – Debt and Equity Securities" accounting guidance.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

KPCo adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements. SFAS 142-3 is included in the "Intangibles – Goodwill and Other" accounting guidance.

FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2)

In February 2008, the FASB issued SFAS 157-2 which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. The fair value hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs. 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.

KPCo adopted SFAS 157-2 effective January 1, 2009. KPCo will apply these requirements to applicable fair value measurements which include new asset retirement obligations and impairment analyses related to long-lived assets, equity investments, goodwill and intangibles. KPCo did not record any fair value measurements for nonrecurring nonfinancial assets and liabilities in the first nine months of 2009. SFAS 157-2 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

FSP SFAS 157-4 "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly" (FSP SFAS 157-4)

In April 2009, the FASB issued FSP SFAS 157-4 providing additional guidance on estimating fair value when the volume and level of activity for an asset or liability has significantly decreased, including guidance on identifying circumstances indicating when a transaction is not orderly. Fair value measurements shall be based on the price that would be received to sell an asset or paid to transfer a liability in an orderly (not a distressed sale or forced liquidation) transaction between market participants at the measurement date under current market conditions. The standard also requires disclosures of the inputs and valuation techniques used to measure fair value and a discussion of changes in valuation techniques and related inputs, if any, for both interim and annual periods.

KPCo adopted the standard effective second quarter of 2009. The standard had no impact on the financial statements but increased disclosure requirements. See "Fair Value Measurements of Financial Assets and Liabilities" section of Note 8. FSP SFAS 157-4 is included in the "Fair Value Measurements and Disclosures" accounting guidance.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts will be disclosed at that time.

ASU 2009-05 "Measuring Liabilities at Fair Value" (ASU 2009-05)

In August 2009, the FASB issued ASU 2009-05 updating the "Fair Value Measurement and Disclosures" accounting guidance. The guidance specifies the valuation techniques that should be used to fair value a liability in the absence of a quoted price in an active market.

The new accounting guidance is effective for interim and annual periods beginning after the issuance date. Although management has not completed an analysis, management does not expect this update to have a material impact on the financial statements. KPCo will adopt ASU 2009-05 effective fourth quarter of 2009.

ASU 2009-12 "Investments in Certain Entities That Calculate Net Asset Value per Share (or its Equivalent)" (ASU 2009-12)

In September 2009, the FASB issued ASU 2009-12 updating the "Fair Value Measurement and Disclosures" accounting guidance for the fair value measurement of investments in certain entities that calculate net asset value per share (or its equivalent). The guidance permits a reporting entity to measure the fair value of an investment within its scope on the basis of the net asset value per share of the investment (or its equivalent).

The new accounting guidance is effective for interim and annual periods ending after December 15, 2009. Although management has not completed an analysis, management does not expect this update to have a material impact on the financial statements. KPCo will adopt ASU 2009-12 effective fourth quarter of 2009.

ASU 2009-13 "Multiple-Deliverable Revenue Arrangements" (ASU 2009-13)

In October 2009, the FASB issued ASU 2009-13 updating the "Revenue Recognition" accounting guidance by providing criteria for separating consideration in multiple-deliverable arrangements. It establishes a selling price hierarchy for determining the price of a deliverable and expands the disclosures related to a vendor's multiple-deliverable revenue arrangements.

The new accounting guidance is effective prospectively for arrangements entered into or materially modified in years beginning after June 15, 2010. Although management has not completed an analysis, management does not expect this update to have a material impact on the financial statements. KPCo will adopt ASU 2009-13 effective January 1, 2011.

SFAS 166 "Accounting for Transfers of Financial Assets" (SFAS 166)

In June 2009, the FASB issued SFAS 166 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

SFAS 166 is effective for interim and annual reporting in fiscal years beginning after November 15, 2009. Early adoption is prohibited. Management continues to review the impact of this standard. KPCo will adopt SFAS 166 effective January 1, 2010. SFAS 166 is included in the "Transfers and Servicing" accounting guidance.

SFAS 167 "Amendments to FASB Interpretation No. 46(R)" (SFAS 167)

In June 2009, the FASB issued SFAS 167 amending the analysis an entity must perform to determine if it has a controlling interest in a variable interest entity (VIE). This new guidance provides that the primary beneficiary of a VIE must have both:

- The power to direct the activities of the VIE that most significantly impact the VIE's economic performance.
- The obligation to absorb the losses of the entity that could potentially be significant to the VIE or the right to receive benefits from the entity that could potentially be significant to the VIE.

The standard also requires separate presentation on the face of the statement of financial position for assets which can only be used to settle obligations of a consolidated VIE and liabilities for which creditors do not have recourse to the general credit of the primary beneficiary.

SFAS 167 is effective for interim and annual reporting in fiscal years beginning after November 15, 2009. Early adoption is prohibited. Management continues to review the impact of the changes in the consolidation guidance on the financial statements. This standard will increase disclosure requirements related to transactions with VIEs and may change the presentation of consolidated VIE's assets and liabilities on KPCo's balance sheets. KPCo will adopt SFAS 167 effective January 1, 2010. SFAS 167 is included in the "Consolidation" accounting guidance.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policies including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. KPCo will adopt the standard effective for the 2009 Annual Report. FSP SFAS 132R-1 is included in the "Compensation – Retirement Benefits" accounting guidance.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, financial instruments, emission allowances, leases, insurance, hedge accounting, discontinued operations and income tax. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

3. RATE MATTERS

As discussed in KPCo's 2008 Annual Report, KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. The Rate Matters note within KPCo's 2008 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 2009 and updates KPCo's 2008 Annual Report.

Kentucky Storm Restoration Expenses

During 2009, KPCo experienced severe storms causing significant customer outages. In August 2009, KPCo filed a petition with the Kentucky Public Service Commission (KPSC) for an order seeking authorization to defer approximately $10 million of incremental storm restoration expense for review and recovery in KPCo's next base rate proceeding. The requested deferral of the previously expensed $10 million is in addition to the annual $2 million of storm-related operation and maintenance expense included in KPCo's current base rates. Management is unable to predict the outcome of this petition. A decision is expected from the KPSC during the fourth quarter of 2009.

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis, these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that the KPSC has the authority to provide for surcharges and surcredits until the court of appeals rules otherwise.

In November 2008, the Kentucky Court of Appeals concluded that Duke Energy's surcharge was illegal. However, the order stated that the "decision was premised on the nature of the long-term capital improvements proposed by Duke Energy as distinguished from the fuel and other surcharges that are fluctuating and unanticipated. The latter have been approved by the Kentucky Supreme Court and remain the law." In February 2009, the Kentucky Court of Appeals denied the KPSC request for appeal of the Franklin County Circuit Court decision. In March 2009, the KPSC filed for a discretionary review of the related Duke Energy case with the Kentucky Supreme Court. Management believes that all of KPCo's variable rate mechanisms are valid and would be upheld if challenged.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. KPCo's portion of recognized gross SECA revenues was $17 million.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers are engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a refund of a portion or all of the unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. KPCo provided reserves of $2.9 million and $400 thousand in 2006 and 2007, respectively.

In February 2009, a settlement agreement was approved by the FERC resulting in the completion of a $1 million settlement applicable to $20 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $10 million applicable to $112 million of SECA revenues. The balance in the reserve for future settlements as of September 30, 2009 was $34 million. KPCo's portion of the reserve balance at September 30, 2009 was $2.6 million. As of September 30, 2009, there were no in-process settlements.

Management cannot predict the ultimate outcome of future settlement discussions or future FERC proceedings or court appeals, if any. However, if the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. If the remaining unsettled SECA claims are settled for considerably more than the to-date settlements or if the remaining unsettled claims cannot be settled and are awarded a refund by the FERC greater than the remaining reserve balance, it could have an adverse effect on net income. Cash flows will be adversely impacted by any additional settlements or ordered refunds.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities even though other non-affiliated entities transmit power over AEP's lines. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain state regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. In August 2009, the United States Court of Appeals issued an opinion affirming FERC's refusal to implement a regional rate design in PJM.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. The AEP East companies sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. In January and March 2009, the AEP East companies received retail rate increases in Tennessee and Indiana, respectively, which recognized the higher retail transmission costs resulting from the loss of wholesale transmission revenues from T&O transactions. As a result, the AEP East companies are now recovering approximately 98% of the lost T&O transmission revenues from their retail customers. The remaining 2% is being incurred by I&M until it can revise its rates in Michigan to recover the lost revenues.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of the AEP East companies' transmission by others in PJM and MISO and, as a result, the use of zonal rates would be unfair and discriminatory to AEP's East zone retail customers. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings to reflect the resultant additional wholesale transmission T&O revenues reduction of transmission cost to retail customers. This case is pending before the U.S. Court of Appeals which in August 2009 ruled against AEP in a similar case. See "The FERC PJM Regional Transmission Rate Proceeding" section above.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers intervened in this filing. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating Agreement, the FERC determined the allocation methodology was reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. Following authorized regulatory treatment, the AEP West companies shared a portion of SIA margins with their customers during the period June 2000 to March 2006. In December 2008, the AEP West companies recorded a provision for refund reflecting the sharing. Management cannot predict the outcome of the requested FERC rehearing proceeding or any future state regulatory proceedings but believes the AEP West companies' provision for refund regarding related future state regulatory proceedings is adequate.

Modification of the Transmission Agreement (TA)

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA entered into in 1984, as amended, that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations operated at 345kV and above. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, WPCo and KGPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs on the basis of the TA parties' 12-month coincident peak and reimburse the majority of PJM transmission revenues based on individual cost of service instead of the MLR method used in the present TA. AEPSC requested the effective date to be the first day of the month following a final non-appealable FERC order. The delayed effective date was approved by the FERC in August 2009 when the FERC accepted the new TA for filing. Settlement discussions are in process. Management is unable to predict the effect, if any, it will have on future net income and cash flows due to timing of the implementation by various state regulators of the FERC's new approved TA.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, established a settlement proceeding with an ALJ and delayed the requested October 2008 effective date for five months. In October 2008, AEP filed the required compliance filing and began settlement discussions with the intervenors and FERC staff. The settlement discussions are currently ongoing.

The requested increase, which the AEP East companies began billing in April 2009 for service as of March 1, 2009, will produce a $63 million annualized increase in revenues. Approximately $8 million of the increase will be collected from nonaffiliated customers within PJM. The remaining $55 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of the AEP East companies' transmission facilities so that retail rates for jurisdictions other than Ohio are not directly affected.

In May 2009, the first annual update of the formula rate was filed with the FERC which reflected increased transmission service revenue requirements of approximately $32 million on an annualized basis, effective for service as of July 1, 2009 to be billed in August 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM.

Under the formula, the second annual update will be filed effective July 1, 2010 and each year thereafter. Also, beginning with the July 1, 2010 update, the rates each year will include an adjustment to true-up the prior year's collections to the actual costs for the prior year. Management is unable to predict the outcome of the settlement discussions or any further proceedings that might be necessary if settlement discussions are not successful.

Transmission Agreement (TA)

Certain transmission facilities placed in service in 1998 in KPCo's service territory were inadvertently excluded from the AEP East companies' TA calculation. As a result, KPCo did not receive a TA credit for this equipment from the other TA member companies. The amount involved was $7 million annually. It was not discovered until February 2009. KPCo's base electric rates were adjusted only once, in April 2006, during the period in which the error was in effect. Effective January 2009, the allocation was revised to give KPCo its full TA credit prospectively and the KPSC staff and attending intervenors were informed about the revision at a meeting in April 2009. Management does not believe that it is probable that a material retroactive rate adjustment will result.

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 adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2008 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to September 30, 2009, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, KPCo will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into replacement leasing arrangements for the equipment affected by this notification prior to the termination date of 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At September 30, 2009, the maximum potential loss for these lease agreements was approximately $251 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

CONTINGENCIES

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases (GHG) under the CAA. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case.

In September 2009, the Second Circuit Court issued a ruling vacating the dismissal and remanding the case to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate GHG emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing CAA authorities, and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. Management believes the actions are without merit and intends to continue to defend against the claims including seeking further review by the Second Circuit and, if necessary, the United States Supreme Court.

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 GHG 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. AEP companies, including KPCo, were initially dismissed from this case without prejudice, but are named as a defendant in a pending fourth amended complaint.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil 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.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management recorded a provision in 2008. In September 2009, the parties reached a settlement and a portion of the provision was reversed.

5. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and nine months ended September 30, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 26	$ 25	$ 11	$ 10
Interest Cost	64	62	27	28
Expected Return on Plan Assets	(80)	(84)	(21)	(27)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	14	10	11	3
Net Periodic Benefit Cost	$ 24	$ 13	$ 35	$ 21

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2009	2008	2009	2008
	(in millions)			
Service Cost	$ 78	$ 75	$ 32	$ 31
Interest Cost	191	187	82	84
Expected Return on Plan Assets	(241)	(252)	(61)	(83)
Amortization of Transition Obligation	-	-	20	21
Amortization of Net Actuarial Loss	44	29	32	8
Net Periodic Benefit Cost	$ 72	$ 39	$ 105	$ 61

The following table provides KPCo's net periodic benefit cost for the plans for the three and nine months ended September 30, 2009 and 2008:

	Pension Plans		Other Postretirement Benefit Plans	
	2009	2008	2009	2008
	(in thousands)			
Three Months Ended September 30,	$ 555	$ 249	$ 808	$ 417
Nine Months Ended September 30,	1,664	747	2,424	1,218

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

Strategies for Utilization of Derivative Instruments to Achieve Objectives

The strategy surrounding the use of derivative instruments focuses on managing risk exposures, future cash flows and creating value based on open trading positions by utilizing both economic and formal hedging strategies. To accomplish these objectives, AEPSC, on behalf of KPCo, primarily employs risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. 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 electricity, coal, natural gas, interest rate and to a lesser degree heating oil, 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. The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with the established risk management policies as approved by the Finance Committee of AEP's Board of Directors.

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of September 30, 2009:

Notional Volume of Derivative Instruments
September 30, 2009

Primary Risk Exposure		Volume	Unit of Measure
		(in thousands)	
Commodity:			
Power		34,748	MWHs
Coal		3,184	Tons
Natural Gas		5,009	MMBtus
Heating Oil and Gasoline		693	Gallons
Interest Rate	$	4,240	USD

Fair Value Hedging Strategies

At certain times, AEPSC, on behalf of KPCo, enters into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These 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. During 2009 and 2008, this strategy was not actively employed.

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 electricity, coal and natural gas ("Commodity") in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. KPCo 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. During 2009 and 2008, KPCo designated cash flow hedging relationships using these commodities.

KPCo's vehicle fleet is exposed to gasoline and diesel fuel price volatility. AEPSC, on behalf of KPCo, enters into financial gasoline and heating oil derivative contracts in order mitigate price risk of future fuel purchases. KPCo does not hedge all fuel price risk. During 2009, KPCo designated cash flow hedging strategies of forecasted fuel purchases. This strategy was not active for KPCo during 2008. For disclosure purposes, these contracts are included with other hedging activity as "Commodity."

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo enters into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated 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. During 2009 and 2008, KPCo did not have any active interest rate cash flow hedge strategies.

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 in the balance sheet 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, 2009 and December 31, 2008 balance sheets, KPCo netted $2 million and $468 thousand of cash collateral received from third parties against short-term and long-term risk management assets, respectively, and $6.6 million and $1.2 million of cash collateral paid to third parties against short-term and long-term risk management liabilities, respectively.

The following table represents the gross fair value impact of KPCo's derivative activity on the Condensed Balance Sheet as of September 30, 2009.

Fair Value of Derivative Instruments
September 30, 2009
(in thousands)

Balance Sheet Location	Risk Management Contracts Commodity (a)	Hedging Contracts Commodity (a)	Hedging Contracts Interest Rate (a)	Other (a) (b)	Total
Current Risk Management Assets	$ 98,668	$ 1,069	$ -	$ (82,580)	$ 17,157
Long-term Risk Management Assets	41,260	263	-	(29,830)	11,693
Total Assets	139,928	1,332	-	(112,410)	28,850
Current Risk Management Liabilities	90,656	977	-	(85,259)	6,374
Long-term Risk Management Liabilities	37,578	351	-	(33,140)	4,789
Total Liabilities	128,234	1,328	-	(118,399)	11,163
Total MTM Derivative Contract Net Assets (Liabilities)	$ 11,694	$ 4	$ -	$ 5,989	$ 17,687

(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 represent counterparty netting of risk management contracts, associated cash collateral in accordance with the accounting guidance for "Derivatives and Hedging" and dedesignated risk management contracts.

The table below presents KPCo's activity of derivative risk management contracts for the three and nine months ended September 30, 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts

Location of Gain (Loss)	Three Months Ended September 30, 2009	Nine Months Ended September 30, 2009
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 4,210	$ 15,985
Sales to AEP Affiliates	(96)	(1,869)
Regulatory Assets	-	-
Regulatory Liabilities	1,229	1,848
Total Gain on Risk Management Contracts	$ 5,343	$ 15,964

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, KPCo 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. 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. 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. Unrealized and 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), KPCo recognizes 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 in Net Income during the period of change.

KPCo records realized 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, 2009 and 2008, this strategy was not actively employed.

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 derivatives transactions for the purchase and sale of electricity, 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 Regulatory Assets or Regulatory Liabilities in KPCo's Condensed Balance Sheet, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to commodities. During the three and nine months ended September 30, 2009 and 2008, KPCo recognized immaterial amounts of hedge ineffectiveness.

Beginning in 2009, AEPSC on behalf of KPCo, executed financial heating oil and gasoline derivative contracts to hedge the price risk of its diesel fuel and gasoline purchased. KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on the Condensed Balance Sheets into Other Operation and Maintenance Expense or Depreciation and Amortization Expense, as it relates to capital projects, on the Condensed Statements of Income. KPCo does not hedge all fuel price exposure. During the three and nine months ended September 30, 2009, KPCo recognized no hedge ineffectiveness related to this hedge strategy.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financing from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During the three and nine months ended September 30, 2009 and 2008, this strategy was not actively employed.

The following tables provide details on designated, effective cash flow hedges included in AOCI on KPCo's Condensed Balance Sheets and the reasons for changes in cash flow hedges for the three and nine months ended September 30, 2009. 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 September 30, 2009
(in thousands)

	Commodity	Interest Rate	Total
Beginning Balance in AOCI as of July 1, 2009	$ 478	$ (493)	$ (15)
Changes in Fair Value Recognized in AOCI	(98)	-	(98)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheets:			
Electric Generation, Transmission and Distribution Revenues	(691)	-	(691)
Fuel and Other Consumables Used for Electric Generation	(9)	-	(9)
Purchased Electricity for Resale	425	-	425
Interest Expense	-	15	15
Property, Plant and Equipment	(5)	-	(5)
Ending Balance in AOCI as of September 30, 2009	$ 100	$ (478)	$ (378)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
For the Nine Months Ended September 30, 2009
(in thousands)

	Commodity	Interest Rate	Total
Beginning Balance in AOCI as of January 1, 2009	$ 584	$ (525)	$ 59
Changes in Fair Value Recognized in AOCI	(84)	-	(84)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheets:			
Electric Generation, Transmission and Distribution Revenues	(1,364)	-	(1,364)
Fuel and Other Consumables Used for Electric Generation	(10)	-	(10)
Purchased Electricity for Resale	980	-	980
Interest Expense	-	47	47
Property, Plant and Equipment	(6)	-	(6)
Ending Balance in AOCI as of September 30, 2009	$ 100	$ (478)	$ (378)

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Condensed Balance Sheet at September 30, 2009 were:

Impact of Cash Flow Hedges on the Condensed Balance Sheet
September 30, 2009

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 688	$ -	$ 688
Hedging Liabilities (a)	(684)	-	(684)
AOCI Gain (Loss) Net of Tax	100	(478)	(378)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	157	(60)	97

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on KPCo's Condensed Balance Sheet.

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, 2009, the maximum length of time that KPCo is hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") exposure to variability in future cash flows related to forecasted transactions is 17 months.

Credit Risk

Management limits credit risk in KPCo's wholesale marketing and trading activities by assessing the creditworthiness of potential counterparties before entering into transactions with them and continuing to evaluate their creditworthiness on an ongoing basis. KPCo uses Moody's, S&P and current market-based qualitative and quantitative data to assess the financial health of counterparties on an ongoing basis. If an external rating is not available, an internal rating is generated utilizing a quantitative tool developed by Moody's to estimate probability of default that corresponds to an implied external agency credit rating.

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

Collateral Triggering Events

Under a limited number of derivative and non-derivative counterparty contracts primarily related to pre-2002 risk management activities and under the tariffs of the RTOs and Independent System Operators (ISOs), KPCo is obligated to post an 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, the risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management believes that a downgrade below investment grade is unlikely. As of September 30, 2009, the aggregate value of such contracts was $1.9 million and KPCo was not required to post any collateral. KPCo would have been required to post $1.9 million of collateral at September 30, 2009 if certain credit ratings had declined below investment grade of which $1.8 million was attributable to RTO and ISO activities.

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 non-performance event under borrowed debt in excess of $50 million. On an ongoing basis, AEPSC's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. As of September 30, 2009, the fair value of these derivative liabilities subject to cross-default provisions totaled $48.5 million prior to consideration of contractual netting arrangements. This exposure has been reduced by cash collateral posted of $668 thousand. Management believes that a non-performance event under these provisions is unlikely. If a cross-default provision would have been triggered, an additional settlement of $8.8 million would be required after considering KPCo's contractual netting arrangements.

8. FAIR VALUE MEASUREMENTS

With the adoption of new accounting guidance, KPCo is required to provide certain fair value disclosures which were previously only required in the annual report. The new accounting guidance did not change the method to calculate the amounts reported on KPCo's Condensed Balance Sheets.

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. 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 at September 30, 2009 and December 31, 2008 are summarized in the following table:

	September 30, 2009		December 31, 2008	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 548,680	$ 598,314	$ 418,555	$ 366,108

Fair Value Measurements of Financial Assets and Liabilities

As described in KPCo's 2008 Annual Report, 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). The Derivatives, Hedging and Fair Value Measurements note within KPCo's 2008 Annual Report should be read in conjunction with this report.

Exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified within 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. Where observable inputs are available for substantially the full term of the asset or liability, the instrument is categorized in Level 2. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. In addition, long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in Level 3. Valuation models utilize various inputs that include quoted prices for similar assets or liabilities in active markets, quoted prices for identical or similar assets or liabilities in 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 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, 2009 and December 31, 2008. 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 as of September 30, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 1,133	$ 132,426	$ 5,556	$ (112,977)	$ 26,138
Cash Flow and Fair Value Hedges (a)	-	1,326	-	(638)	688
Dedesignated Risk Management Contracts (b)	-	-	-	2,024	2,024
Total Risk Management Assets	$ 1,133	$ 133,752	$ 5,556	$ (111,591)	$ 28,850
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 1,232	$ 125,398	$ 790	$ (117,639)	$ 9,781
Cash Flow and Fair Value Hedges (a)	-	1,322	-	(638)	684
DETM Assignment (c)	-	-	-	698	698
Total Risk Management Liabilities	$ 1,232	$ 126,720	$ 790	$ (117,579)	$ 11,163

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,443	$ 140,387	$ 2,561	$ (125,636)	$ 20,755
Cash Flow and Fair Value Hedges (a)	-	1,418	-	(302)	1,116
Dedesignated Risk Management Contracts (b)	-	-	-	2,749	2,749
Total Risk Management Assets	$ 3,443	$ 141,805	$ 2,561	$ (123,189)	$ 24,620
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,021	$ 132,087	$ 848	$ (126,370)	$ 10,586
Cash Flow and Fair Value Hedges (a)	-	544	-	(302)	242
DETM Assignment (c)	-	-	-	1,118	1,118
Total Risk Management Liabilities	$ 4,021	$ 132,631	$ 848	$ (125,554)	$ 11,946

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

(b) "Dedesignated Risk Management Contracts" are 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 will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 12 in KPCo's 2008 Annual Report.

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

Three Months Ended September 30, 2009	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of July 1, 2009	$ 2,801
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(557)
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	-
Transfers in and/or out of Level 3 (b)	468
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	2,054
Balance as of September 30, 2009	$ 4,766

Nine Months Ended September 30, 2009	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of January 1, 2009	$ 1,713
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	(1,379)
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	-
Transfers in and/or out of Level 3 (b)	(70)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	4,502
Balance as of September 30, 2009	$ 4,766

Three Months Ended September 30, 2008	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of July 1, 2008	$ (3,970)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	956
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	-
Transfers in and/or out of Level 3 (b)	1,196
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	831
Balance as of September 30, 2008	$ (987)

Nine Months Ended September 30, 2008	Net Risk Management Assets (Liabilities)
	(in thousands)
Balance as of January 1, 2008	$ (157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	79
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	-
Transfers in and/or out of Level 3 (b)	(146)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(763)
Balance as of September 30, 2008	$ (987)

(a) Included in revenues on KPCo's Condensed Statements of Income.

(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on KPCo's Condensed Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

9. INCOME TAXES

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

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2006 and have issues that are being pursued at the appeals level. The years 2007 and 2008 are currently under examination. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

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

KPCo is changing the tax method of accounting for the definition of a unit of property for generation assets. This change will provide a favorable cash flow benefit to KPCo in 2009 and 2010.

Federal Tax Legislation

The American Recovery and Reinvestment Act of 2009 was signed into law by the President in February 2009. It 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 are not expected to have a material impact on net income or financial condition. However, management forecasts the bonus depreciation provision could provide a significant favorable cash flow benefit in 2009.

10. FINANCING ACTIVITIES

Long-term Debt

Long-term debt issued during the first nine months of 2009 were:

Type of Debt	Principal Amount (in thousands)	Interest Rate	Due Date
Senior Unsecured Notes	$ 40,000	7.25%	2021
Senior Unsecured Notes	30,000	8.03%	2029
Senior Unsecured Notes	60,000	8.13%	2039

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of September 30, 2009 and December 31, 2008 are included in Advances to/from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the nine months ended September 30, 2009 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	Loans to Utility Money Pool as of September 30, 2009	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 174,108	$ 18,403	$ 122,132	$ 8,493	$ 4,197	$ 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, 2009 and 2008 are summarized in the following table:

	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2009	2.28%	0.27%	0.63%	0.28%	1.33%	0.50%
2008	5.37%	2.91%	-%	-%	3.24%	-%

Credit Facilities

KPCo and certain other companies in the AEP System have a $627 million 3-year credit agreement. Under the facility, letters of credit may be issued. As of September 30, 2009, there were no outstanding amounts for KPCo under this credit facility. KPCo and certain other companies in the AEP System had a $350 million 364-day credit agreement that expired in April 2009.

Sales of Receivables

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash.

In July 2009, AEP Credit renewed and increased its sale of receivables agreement. The sale of receivables agreement provides a commitment of $750 million from bank conduits to purchase receivables. This agreement will expire in July 2010. The previous sale of receivables agreement provided a commitment of $700 million.

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Kentucky Power Company

2008 Annual Report

KPSC Case No. 2009-00459
Pursuant to 807 KAR5:001
Section 10 (6) (s)
2008 KPCO Annual Report
2008 First Qtr. Report
2008 Second Qtr. Report
2008 Third Qtr. Report

Financial Statements

AEP AMERICAN® ELECTRIC POWER

TABLE OF CONTENTS

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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.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
CWIP	Construction Work in Progress.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EIS	Energy Insurance Services, Inc., a protected cell insurance company that AEP consolidates due to FIN 46.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 46R	FIN 46R, "Consolidation of Variable Interest Entities."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
FSP	FASB Staff Position.
FSP FIN 39-1	FSP FIN 39-1, "Amendment of FASB Interpretation No. 39."
GAAP	Accounting Principles Generally Accepted in the United States of America.

Term	Meaning
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
MW	Megawatt.
NO_x	Nitrogen oxide.
NSR	New Source Review.
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.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 107	Statement of Financial Accounting Standards No. 107, "Disclosures about Fair Value of Financial Investments."
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 141R	Statement of Financial Accounting Standards No. 141 (revised 2007), "Business Combinations."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying balance sheets of Kentucky Power Company (the "Company") as of December 31, 2008 and 2007, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2008. 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 generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing 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 over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2008 and 2007, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 9 to the financial statements, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes," effective January 1, 2007. As discussed in Note 6 to the financial statements, the Company adopted FASB Statement No. 158, "Accounting for Defined Benefit Pension and Other Postretirement Plans", effective December 31, 2006.

Deloitte & Touche LLP

Columbus, Ohio
February 27, 2009

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

	2008	2007	2006
REVENUES			
Electric Generation, Transmission and Distribution	$ 597,699	$ 526,754	$ 526,432
Sales to AEP Affiliates	66,249	60,551	58,287
Other	1,612	695	1,148
TOTAL	665,560	588,000	585,867
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	171,215	147,912	152,335
Purchased Electricity for Resale	26,157	17,786	8,724
Purchased Electricity from AEP Affiliates	234,379	185,399	192,080
Other Operation	64,330	66,118	60,674
Maintenance	47,921	36,880	35,430
Depreciation and Amortization	48,067	47,193	46,387
Taxes Other Than Income Taxes	9,644	11,872	8,612
TOTAL	601,713	513,160	504,242
OPERATING INCOME	63,847	74,840	81,625
Other Income (Expense):			
Interest Income	2,103	1,992	656
Allowance for Equity Funds Used During Construction	1,012	260	241
Interest Expense	(34,535)	(28,635)	(28,832)
INCOME BEFORE INCOME TAX EXPENSE	32,427	48,457	53,690
Income Tax Expense	7,896	15,987	18,655
NET INCOME	$ 24,531	$ 32,470	$ 35,035

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

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2005	$ 50,450	$ 208,750	$ 88,864	$ (223)	$ 347,841
Common Stock Dividends			(15,000)		(15,000)
TOTAL					332,841
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $940				1,746	1,746
Minimum Pension Liability, Net of Tax of $16				29	29
NET INCOME			35,035		35,035
TOTAL COMPREHENSIVE INCOME					36,810
DECEMBER 31, 2006	50,450	208,750	108,899	1,552	369,651
FIN 48 Adoption, Net of Tax			(786)		(786)
Common Stock Dividends			(12,000)		(12,000)
TOTAL					356,865
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,274				(2,366)	(2,366)
NET INCOME			32,470		32,470
TOTAL COMPREHENSIVE INCOME					30,104
DECEMBER 31, 2007	50,450	208,750	128,583	(814)	386,969
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(14,000)		(14,000)
TOTAL					372,604
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $470				873	873
NET INCOME			24,531		24,531
TOTAL COMPREHENSIVE INCOME					25,404
DECEMBER 31, 2008	$ 50,450	$ 208,750	$ 138,749	$ 59	$ 398,008

See Notes to Financial Statements.

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

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 646	$ 727
Accounts Receivable:		
Customers	21,681	20,196
Affiliated Companies	6,721	15,984
Accrued Unbilled Revenues	2,533	2,904
Miscellaneous	83	178
Allowance for Uncollectible Accounts	(1,144)	(1,071)
Total Accounts Receivable	29,874	38,191
Fuel	29,440	8,338
Materials and Supplies	10,630	11,758
Risk Management Assets	13,760	12,121
Regulatory Asset for Under-Recovered Fuel Costs	9,953	4,426
Margin Deposits	5,207	1,940
Prepayments and Other	5,751	2,084
TOTAL	105,261	79,585
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	533,998	482,653
Transmission	431,835	402,259
Distribution	528,711	502,486
Other	65,485	61,665
Construction Work in Progress	46,650	46,439
Total	1,606,679	1,495,502
Accumulated Depreciation and Amortization	476,568	457,028
TOTAL - NET	1,130,111	1,038,474
OTHER NONCURRENT ASSETS		
Regulatory Assets	179,845	124,828
Long-term Risk Management Assets	10,860	14,826
Deferred Charges and Other	41,884	53,708
TOTAL	232,589	193,362
TOTAL ASSETS	$ 1,467,961	$ 1,311,421

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2008 and 2007

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 131,399	$ 19,153
Accounts Payable:		
General	35,584	32,603
Affiliated Companies	45,245	29,437
Long-term Debt Due Within One Year – Nonaffiliated	-	30,000
Risk Management Liabilities	6,316	10,310
Customer Deposits	15,985	14,422
Accrued Taxes	11,903	16,875
Other	29,526	31,909
TOTAL	275,958	184,709
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,555	398,373
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	5,630	9,699
Deferred Income Taxes	259,666	240,858
Regulatory Liabilities and Deferred Investment Tax Credits	46,135	46,434
Deferred Credits and Other	64,009	24,379
TOTAL	793,995	739,743
TOTAL LIABILITIES	1,069,953	924,452
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	208,750	208,750
Retained Earnings	138,749	128,583
Accumulated Other Comprehensive Income (Loss)	59	(814)
TOTAL	398,008	386,969
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,467,961	$ 1,311,421

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007 and 2006
(in thousands)

	2008	2007	2006
OPERATING ACTIVITIES			
Net Income	$ 24,531	$ 32,470	$ 35,035
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	48,067	47,193	46,387
Deferred Income Taxes	4,097	5,691	2,596
Allowance for Equity Funds Used During Construction	(1,012)	(260)	(241)
Mark-to-Market of Risk Management Contracts	(4,650)	89	(3,917)
Change in Other Noncurrent Assets	(11,298)	(4,122)	(4,497)
Change in Other Noncurrent Liabilities	2,055	1,001	2,621
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	8,317	2,445	11,903
Fuel, Materials and Supplies	(18,866)	9,015	(6,125)
Accounts Payable	21,288	1,806	(3,436)
Accrued Taxes, Net	(4,199)	(1,410)	15,547
Other Current Assets	(9,481)	(2,968)	6,107
Other Current Liabilities	2,473	2,744	4,662
Net Cash Flows from Operating Activities	61,322	93,694	106,642
INVESTING ACTIVITIES			
Construction Expenditures	(129,619)	(68,134)	(77,848)
Change in Other Cash Deposits	-	-	5
Acquisitions of Assets	(314)	-	-
Proceeds from Sales of Assets	947	695	2,956
Net Cash Flows Used for Investing Activities	(128,986)	(67,439)	(74,887)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	-	321,100	-
Change in Advances from Affiliates, Net	112,246	(11,483)	24,596
Retirement of Long-term Debt – Nonaffiliated	(30,000)	(322,964)	-
Retirement of Long-term Debt – Affiliated	-	-	(40,000)
Principal Payments for Capital Lease Obligations	(806)	(883)	(1,175)
Dividends Paid on Common Stock	(14,000)	(12,000)	(15,000)
Other	143	-	-
Net Cash Flows from (Used for) Financing Activities	67,583	(26,230)	(31,579)
Net Increase (Decrease) in Cash and Cash Equivalents	(81)	25	176
Cash and Cash Equivalents at Beginning of Period	727	702	526
Cash and Cash Equivalents at End of Period	$ 646	$ 727	$ 702
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 28,602	$ 28,864	$ 27,887
Net Cash Paid for Income Taxes	3,554	10,477	11,516
Noncash Acquisitions Under Capital Leases	544	826	648
Construction Expenditures Included in Accounts Payable at December 31,	9,662	12,161	3,357
Revenue Refund Included in Accounts Payable at December 31,	18,526	-	-

See Notes to Financial Statements.

NOTES TO FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements
3. Rate Matters
4. Effects of Regulation
5. Commitments, Guarantees and Contingencies
6. Benefit Plans
7. Business Segments
8. Derivatives, Hedging and Fair Value Measurements
9. Income Taxes
10. Leases
11. Financing Activities
12. Related Party Transactions
13. Property, Plant and Equipment
14. Unaudited Quarterly Financial Information

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 176,000 retail customers in its service territory in eastern Kentucky. As a member of the AEP Power Pool, KPCo shares the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. KPCo also sells power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Under a unit power agreement with AEGCo, an affiliated company that is not a member of the AEP Power Pool, KPCo purchases 15% of the total output of the 2,600 MW Rockport Plant capacity. Therefore, KPCo purchases 390 MW 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.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT 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. Accordingly, the 2006 net income and cash flows reflect nine months of the SIA change.

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

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

The KPSC approves retail rates and regulates the retail services and operations for the generation and supply of power and retail transmission and distribution energy delivery services. KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, are regulated by the FERC under the 2005 Public Utility Holding Company Act, the Federal Power Act and by the KPSC. The FERC also has jurisdiction over the issuances and acquisitions of securities of the public utility holding company subsidiaries, such as KPCo, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. A FERC order in 2008 pursuant to the Federal Power Act codified that for non-power goods and services, a non-regulated affiliate can bill a public utility company no more than market while a public utility must bill the higher of cost or market to a non-regulated affiliate.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission services. KPCo's wholesale power transactions are generally market-based. They 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 enters into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the System Transmission Integration Agreement, the Transmission Equalization Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the AEP subsidiaries that are parties to each agreement, including KPCo.

The KPSC regulates all of the retail public utility services/operations (generation/power supply, transmission and distribution operations) and rates for KPCo, which are cost-based. Both the FERC and the KPSC are permitted to review and audit the books and records of KPCo.

Accounting for the Effects of Cost-Based Regulation

As a cost-based 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 SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues.

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, 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.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for cost-based rate-regulated operations under the group composite method of 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. 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 depreciation rates that are established for the generating plants 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 SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets." 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 and investment is the amount at which that asset and 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 and Cash Equivalents, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

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, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable for KPCo. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from KPCo's balance sheet (see "Sale of Receivables - AEP Credit" section of Note 11).

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, 2008.

KPCo monitors credit levels and the financial condition of its 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.

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. In Kentucky, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, the KPSC audits fuel cost calculations and deferrals. When a fuel cost disallowance becomes probable, KPCo adjusts its deferrals and records provisions for estimated refunds to recognize the probable outcomes. In general, changes in fuel costs are reflected in rates in a timely manner through the fuel cost adjustment clause. A portion of profits from off-system sales are shared with customers through the fuel clause.

Revenue Recognition

Regulatory Accounting

The financial statements for cost-based rate-regulated operations 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 by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and/or financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on the balance sheet. KPCo tests for probability of recovery at each balance sheet date or whenever new events occur. Examples 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.

Traditional 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 in the financial statements upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply power to customers. These power sales and purchases are reported on a net basis in Revenues in the Statements of Income.

Physical energy purchases, including those from all RTOs that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale in the Statements of Income.

KPCo records expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo, which operates solely in a jurisdiction where the generation /supply business is subject to cost-based regulation, defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

AEPSC, on behalf of the AEP East companies, engages in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. 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 in 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 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 Accumulated Other Comprehensive Income into revenues or expenses within the same financial statement line item as the forecasted transaction on its Statements of Income. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Cash Flow Hedging Strategies" section of Note 8.

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 FIN 48. Effective with the adoption of FIN 48 beginning January 1, 2007, KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation.

Excise Taxes

KPCo, as an agent for some state and local governments, collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not record 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 associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting 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.

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 and the State of Kentucky, respectively. 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 Other Noncurrent Assets-Deferred Charges and Other. 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. Allowances held for speculation are included in Current Assets-Prepayments and Other. 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 costs and the amortization of regulatory assets.

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).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. AOCI for KPCo as of December 31, 2008 and 2007 is shown in the following table:

	December 31, 2008	December 31, 2007
Components	**(in thousands)**	
Cash Flow Hedges	$ 59	$ (814)

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Reclassifications

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

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of final pronouncements that management has determined relate to KPCo's operations.

Pronouncements Adopted in 2008

The following standards were effective during 2008. Consequently, the financial statements and footnotes reflect their impact.

SFAS 157 "Fair Value Measurements" (SFAS 157)

KPCo partially adopted SFAS 157 effective January 1, 2008. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures.

In February 2008, the FASB issued FSP SFAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" (SFAS 157-1) which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. SFAS 157-1 was effective upon issuance and had an immaterial impact on the financial statements.

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). KPCo fully adopted SFAS 157 effective January 1, 2009 for items within the scope of SFAS 157-2. The adoption of SFAS 157-2 had an immaterial impact on the financial statements.

In October 2008, the FASB issued FSP SFAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on the financial statements.

See "SFAS 157 Fair Value Measurements" Section of Note 8 for further information.

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

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

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

SFAS 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162)

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

KPCo adopted SFAS 162 in the fourth quarter of 2008. The adoption of this standard had no impact on the financial statements.

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

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement if the employer agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) retrospective application to all prior periods. KPCo adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $562 thousand, ($365 thousand, net of tax) to beginning retained earnings.

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

In June 2007, the FASB addressed the recognition of income tax benefits of dividends on employee share-based compensation. Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

KPCo adopted EITF 06-11 effective January 1, 2008. The adoption of this standard will have an immaterial impact on the financial statements.

FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" (FSP SFAS 133-1 and FIN 45-4)

In September 2008, the FASB issued FSP SFAS 133-1 and FIN 45-4 amending SFAS 133 and FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

KPCo adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements and footnote disclosures.

FSP SFAS 140-4 and FIN 46R-8 "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities" (FSP SFAS 140-4 and FIN 46R-8)

In December 2008, the FASB issued FSP SFAS 140-4 and FIN 46R-8 amending SFAS 140 "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities" and FIN 46R "Consolidation of Variable Interest Entities." Under the requirements, the transferor of financial assets in the securitization or asset-backed financing arrangement must disclose the following:

(a) Nature of any restrictions on assets reported by an entity in its balance sheet that relate to a transferred financial asset, including the carrying amounts of such assets.
(b) Method of reporting servicing assets and servicing liabilities.
(c) If reported as sales and the transferor has continuing involvement with the transferred financial assets and the transfers are accounted for as secured borrowings, how the transfer of financial assets affects the transferors' balance sheet, net income and cash flows.

The FIN 46R amendments contain disclosure requirements for a public enterprise that (a) is the primary beneficiary of a variable interest entity (VIE), (b) holds a significant variable interest in a VIE but is not the primary beneficiary or (c) is a sponsor that holds a variable interest in a VIE. The principle objectives of the disclosures required by this standard are to provide financial statement users an understanding of:

(a) Significant judgments and assumptions made to determine whether to consolidate a variable interest entity and/or disclose information about involvement with a variable interest entity.
(b) Nature of the restrictions on a consolidated variable interest entity's assets reported in the balance sheet, including the carrying amounts of such assets.
(c) Nature of, and changes in, risks associated with a company's involvement with a variable interest entity.
(d) A variable interest entity's effect on the balance sheet, net income and cash flows.
(e) The nature, purpose, size and activities of any variable interest equity, including how it is financed.

KPCo adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements but increased the footnote disclosures for variable interest entities. See "Variable Interest Entities" section of Note 12.

FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FSP FIN 39-1)

In April 2007, the FASB issued FSP FIN 39-1 amending FIN 39, "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. The amendment requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

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

December 2007 10-K Balance Sheet Line Description	FSP FIN 39-1 Reclassification
Current Assets:	(in thousands)
Risk Management Assets	$ (359)
Prepayments and Other	(677)
Long-term Risk Management Assets	(530)
Current Liabilities:	
Risk Management Liabilities	(664)
Customer Deposits	(890)
Long-term Risk Management Liabilities	(12)

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, 2008 balance sheet, KPCo netted $468 thousand of cash collateral received from third parties against short-term and long-term risk management assets and $1.2 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

<u>Pronouncements Adopted During The First Quarter of 2009</u>

The following standards are effective during the first quarter of 2009. Consequently, their impact will be reflected in the first quarter of 2009 financial statements when filed. The following paragraphs discuss their expected impact on future financial statement and footnote disclosures.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. KPCo does not have any such tax positions that result in adjustments.

KPCo adopted SFAS 141R effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. KPCo will apply it to any future business combinations.

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. The statement requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

KPCo adopted SFAS 160 effective January 1, 2009. The adoption of this standard had no impact.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation.

KPCo adopted SFAS 161 effective January 1, 2009. This standard will increase the disclosure requirements related to derivative instruments and hedging activities in future reports.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

KPCo adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as KPCo reports fair value of long-term debt annually.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

KPCo adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

KPCo adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. KPCo will adopt the standard effective for the 2009 Annual Report.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, insurance, hedge accounting, trading inventory and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

3. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on net income and cash flows.

For discussion of the FERC's November 2008 order on AEP's allocation of off-system sales, see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that it has the authority to provide for surcharges and surcredits until the court of appeals rules otherwise.

In November 2008, the Kentucky Court of Appeals concluded that Duke Energy's surcharge was illegal. However, the order stated that the "decision was premised on the nature of the long-term capital improvements proposed by Duke Energy as distinguished from the fuel increases that are fluctuating and unanticipated. The latter have been approved by the Kentucky Supreme Court and remain the law". In February 2009, the Kentucky Court of Appeals denied the KPSC request for appeal of the Franklin County Circuit Court decision. Management believes that all of KPCo's variable rate mechanisms are valid and would be upheld if ever challenged.

2008 Fuel Cost Reconciliation

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM's implementation of PJM transmission marginal line loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo's semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM. For the year ended December 31, 2008, KPCo recorded $20 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through December 2008 of which $7 million related to 2007.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC's direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. KPCo's portion of recognized gross SECA revenues was $17 million.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers have engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $39 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. KPCo provided reserves of $2.9 million and $400 thousand in 2006 and 2007, respectively.

In December 2008, an additional settlement agreement was approved by the FERC resulting in the completion of a $2 million settlement applicable to $17 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $9 million applicable to $92 million of SECA revenues. The balance in the reserve for future settlements as of December 2008 was $35 million. KPCo's reserve balance at December 31, 2008 was $2.6 million. In-process settlements total $1 million applicable to $20 million of SECA revenues. In February 2009, the FERC approved the in-process settlements resulting in the completion of a $1 million settlement application to $20 million of SECA revenues.

If the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing

AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. The remaining 20% is being incurred by AEP until it can revise its rates in Indiana and Michigan to recover these lost revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of its portion of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future net income and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 20% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in a combined increase in annual revenues for the AEP East companies of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of AEP's transmission facilities so that retail rates are not affected. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. In October 2008, AEP began settlement discussions and filed the required compliance filing. Management is unable to predict the outcome of this filing.

Allocation of Off-system Sales Margins

In August 2008, the OCC filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the AEP SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the AEP SIA and to have the AEP East companies issue refunds to the AEP West companies. Although the FERC determined that AEP deviated from the CSW Operating

Agreement, the FERC determined the allocation methodology to be reasonable. The FERC ordered AEP to submit a revised CSW Operating Agreement for the period June 2000 to March 2006. In December 2008, AEP filed a motion for rehearing and a revised CSW Operating Agreement for the period June 2000 to March 2006. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies. The AEP West companies were required to share a portion of such revenues with their wholesale and retail customers during this period. In December 2008, the AEP West companies recorded a provision for refund which had a $97 million unfavorable effect on AEP net income.

The table below lists the respective amounts the AEP East companies and the AEP West companies recorded in December 2008 including the net increase (decrease) to net income for the year ended December 31, 2008:

	Amounts to be (Transferred)/ Received Including Interest	Increase/ (Decrease) to Net Income
AEP East Companies	(in millions)	
APCo	$ (77)	$ (50)
I&M	(48)	(32)
OPCo	(62)	(40)
CSPCo	(44)	(28)
KPCo	(19)	(12)
Total – AEP East Companies	(250)	(162)
AEP West Companies		
PSO	72	12
SWEPCo	85	20
TCC	68	23
TNC	25	10
Total – AEP West Companies	250	65
Total – AEP Consolidated	$ -	$ (97)

The table below shows the vintage year of the associated AEP SIA refunds:

	For the Twelve Months Ended December 31,			
	2006 and Prior	2007	2008	Total
AEP East Companies	(in millions)			
APCo	$ (66)	$ (6)	$ (5)	$ (77)
I&M	(41)	(4)	(3)	(48)
OPCo	(53)	(5)	(4)	(62)
CSPCo	(40)	(3)	(1)	(44)
KPCo	(17)	(1)	(1)	(19)
Total – AEP East Companies	(217)	(19)	(14)	(250)
AEP West Companies				
PSO	62	6	4	72
SWEPCo	74	6	5	85
TCC	59	5	4	68
TNC	22	2	1	25
Total – AEP West Companies	217	19	14	250
Total – AEP Consolidated	$ -	$ -	$ -	$ -

Management cannot predict the outcome of the requested FERC rehearing proceeding or any future regulatory proceedings but believes the provision regarding future regulatory proceedings is adequate.

Transmission Equalization Agreement

Certain transmission equipment placed in service in 1998 in KPCo's service territory was inadvertently excluded from the AEP East companies' TEA calculation. As a result, KPCo did not receive a TEA credit from the other TEA member companies to equalize its investment in this equipment. Management believes that it is not probable that a material retroactive adjustment will result from the omission. However, if a retroactive adjustment is required, it could have an effect on future net income, cash flows and financial condition.

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2008	December 31, 2007	Notes
Regulatory Assets:			
	(in thousands)		
Current Regulatory Asset			
Under-recovered Fuel Costs	$ 9,953	$ 4,426	(a) (f)
Noncurrent Regulatory Assets			
SFAS 109 Regulatory Asset, Net (See Note 9)	$ 107,953	$ 101,340	(a) (d)
SFAS 158 Regulatory Asset (See Note 6)	61,439	13,573	(a) (d)
Other	10,453	9,915	(b) (d)
Total Noncurrent Regulatory Assets	$ 179,845	$ 124,828	
Regulatory Liabilities:			
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Asset Removal Costs	$ 31,874	$ 33,106	(c)
Unrealized Gain on Forward Commitments	11,697	9,592	(a) (d)
Deferred Investment Tax Credits	2,519	3,395	(a) (e)
Other	45	341	(a) (d)
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 46,135	$ 46,434	

(a) Amount does not earn a return.
(b) A portion of this amount earns a return.
(c) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(d) Recovery/refund period – various periods.
(e) Recovery/refund period – up to 11 years.
(f) Recovery/refund period – 1 year.

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 adverse effect on the financial statements.

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. The insurance includes coverage for 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 a South Carolina domiciled insurance company, EIS, together with and/or in addition to various industry mutual and 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 have a material adverse effect on net income, cash flows and financial condition.

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. Budgeted construction expenditures for 2009 are $61.9 million. Budgeted 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.

KPCo 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. Management does not expect to incur penalty payments under these provisions that would materially affect net income, cash flows or financial condition.

The following table summarizes KPCo's actual contractual commitments at December 31, 2008:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 164.4	$ 218.7	$ 58.8	$ -	$ 441.9
Energy and Capacity Purchase Contracts (b)	0.6	1.8	0.3	-	2.7
Construction Contracts for Capital Assets (c)	0.3	5.3	9.3	-	14.9
Total	$ 165.3	$ 225.8	$ 68.4	$ -	$ 459.5

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel. The longest contract extends to the year 2012. The contracts provide for periodic price adjustments and contain various clauses that would release KPCo from its commitments under certain conditions.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets that are contractual commitments.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to December 31, 2008, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity conducted pursuant to the SIA.

Lease Obligations

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

CONTINGENCIES

Environmental Settlement

In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging that certain of KPCo's affiliates including APCo, CSPCo, I&M and OPCo modified units at certain of their coal-fired generating plants in violation of the New Source Review (NSR) requirements of the CAA.

As part of a global consent decree covering all coal-fired units in the five eastern states of the AEP System to resolve all past NSR allegations and secure a covenant not to sue for future claims from the Federal EPA, KPCo agreed to complete previously announced flue gas desulfurization emissions control equipment (scrubbers) on Unit 2 of the Big Sandy Plant by December 2015. The obligation to pay a $15 million civil penalty and provide $36 million for environmental mitigation projects coordinated with the federal government and $24 million to the states for environmental mitigation was shared by members of the AEP Power Pool. Under the consent decree, KPCo recorded its share of the costs of $5.2 million in Other Operation during the third quarter of 2007.

Management believes KPCo can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through regulated rates or market prices of electricity. If KPCo is unable to recover such costs, it would adversely affect KPCo's future net income, cash flows and possibly financial condition.

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of the lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

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 (PCBs) and other hazardous and nonhazardous materials. KPCo currently incurs costs to safely dispose of these substances.

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. At December 31, 2008, 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 Superfund site separately, but several general statements can be made regarding potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was 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.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and certain other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. Management asserted claims against certain companies that sold power to KPCo and certain other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities. Management is unable to predict the ultimate outcome of these proceedings or their impact on future net income and cash flows.

6. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans (merged at December 31, 2008) and unfunded nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. KPCo participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

KPCo adopted SFAS 158 in December 2006 and recognized the obligations associated with defined benefit pension plans and OPEB plans in its balance sheets. 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 SFAS 71 regulatory asset for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes are deferred for future recovery. The effect of this standard on the 2006 financial statements was a pretax AOCI adjustment that was fully offset by a SFAS 71 regulatory asset.

SFAS 158 requires adjustment of pretax AOCI at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount 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 and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating market conditions, investment returns and discount rates.

The following tables provide a reconciliation of the changes in projected benefit obligations and fair value of assets for AEP's plans over the two-year period ending at the plan's measurement date of December 31, 2008, and their funded status as of December 31 for each year:

Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
	(in millions)			
Change in Projected Benefit Obligation				
Projected Obligation at January 1	$ 4,109	$ 4,108	$ 1,773	$ 1,818
Service Cost	100	96	42	42
Interest Cost	249	235	113	104
Actuarial Loss (Gain)	139	(64)	2	(91)
Plan Amendments	-	18	-	-
Benefit Payments	(296)	(284)	(120)	(130)
Participant Contributions	-	-	24	22
Medicare Subsidy	-	-	9	8
Projected Obligation at December 31	$ 4,301	$ 4,109	$ 1,843	$ 1,773
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,504	$ 4,346	$ 1,400	$ 1,302
Actual Gain (Loss) on Plan Assets	(1,054)	435	(368)	115
Company Contributions	7	7	82	91
Participant Contributions	-	-	24	22
Benefit Payments	(296)	(284)	(120)	(130)
Fair Value of Plan Assets at December 31	$ 3,161	$ 4,504	$ 1,018	$ 1,400
Funded (Underfunded) Status at December 31	$ (1,140)	$ 395	$ (825)	$ (373)

AEP has significant investments in several trust funds to provide for future pension and OPEB payments. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are lower, this decline has not affected the funds' ability to make their required payments.

Amounts Recognized on AEP's Balance Sheets as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ -	$ 482	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(9)	(8)	(4)	(4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(1,131)	(79)	(821)	(369)
Funded (Underfunded) Status	$ (1,140)	$ 395	$ (825)	$ (373)

SFAS 158 Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2008, 2007 and 2006

	Pension Plans			Other Postretirement Benefit Plans		
	2008	2007	2006	2008	2007	2006
Components	(in millions)					
Net Actuarial Loss	$ 2,024	$ 534	$ 759	$ 715	$ 231	$ 354
Prior Service Cost (Credit)	13	14	(5)	3	4	4
Transition Obligation	-	-	-	70	97	124
Pretax AOCI	$ 2,037	$ 548	$ 754	$ 788	$ 332	$ 482
Recorded as						
Regulatory Assets	$ 1,660	$ 453	$ 582	$ 502	$ 204	$ 293
Deferred Income Taxes	132	33	60	100	45	66
Net of Tax AOCI	245	62	112	186	83	123
Pretax AOCI	$ 2,037	$ 548	$ 754	$ 788	$ 332	$ 482

Components of the Change in AEP's Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2008 and 2007 are as follows:

	Pensions Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
Components	(in millions)			
Actuarial Loss (Gain) During the Year	$ 1,527	$ (166)	$ 492	$ (111)
Amortization of Actuarial Loss	(37)	(59)	(9)	(12)
Prior Service Cost (Credit)	(1)	19	-	-
Amortization of Transition Obligation	-	-	(27)	(27)
Total Pretax AOCI Change for the Year	$ 1,489	$ (206)	$ 456	$ (150)

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2008 and 2007, and the target allocation for 2009, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2009	2008	2007
Asset Category			
Equity Securities	55%	47%	57%
Real Estate	5%	6%	6%
Debt Securities	39%	42%	36%
Cash and Cash Equivalents	1%	5%	1%
Total	100%	100%	100%

The asset allocations for AEP's OPEB plans at the end of 2008 and 2007, and target allocation for 2009, by asset category, are as follows:

Asset Category	Target Allocation 2009	Percentage of Plan Assets at Year End 2008	2007
Equity Securities	65%	53%	62%
Debt Securities	34%	43%	35%
Cash and Cash Equivalents	1%	4%	3%
Total	100%	100%	100%

AEP's investment strategy for the employee benefit 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 plans' assets relative to the plans' liabilities. To minimize investment risk, AEP's employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to AEP's targeted allocation when considered appropriate. AEP's 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. AEP's investment policies prohibit the benefit trust funds from purchasing AEP securities (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, AEP's 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, including the Employee Retirement Income Security Act (ERISA).

The value of the pension plans' assets decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007. The qualified plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of AEP's OPEB plans' assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007. The OPEB plans paid $120 million in benefits to plan participants during 2008.

AEP bases the 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.

Accumulated Benefit Obligation	December 31, 2008 (in millions)	2007
Qualified Pension Plans	$ 4,119	$ 3,914
Nonqualified Pension Plans	80	77
Total	$ 4,199	$ 3,991

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 at December 31, 2008 and 2007 were as follows:

	Underfunded Pension Plans December 31, 2008 (in millions)	2007
Projected Benefit Obligation	$ 4,301	$ 81
Accumulated Benefit Obligation	$ 4,199	$ 77
Fair Value of Plan Assets	3,161	-
Underfunded Accumulated Benefit Obligation	$ 1,038	$ 77

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31, used in the measurement of AEP's benefit obligations are shown in the following tables:

Assumptions	Pension Plans 2008	Pension Plans 2007	Other Postretirement Benefit Plans 2008	Other Postretirement Benefit Plans 2007
Discount Rate	6.00%	6.00%	6.10%	6.20%
Rate of Compensation Increase	5.90%(a)	5.90%(a)	N/A	N/A

(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.

N/A = Not Applicable

To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2008, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2009 expected cash flows for the pension (qualified and nonqualified) and OPEB plans is as follows:

Employer Contributions	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Required Contributions (a)	$ 9	$ 4
Additional Discretionary Contributions	-	158

(a) Contribution required to meet minimum funding requirement under ERISA plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by ERISA plus the amount to pay unfunded nonqualified benefits. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of AEP's Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from the employer's assets, including both the employer's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. 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 AEP's pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2009	$ 378	$ 116	$ (10)
2010	379	126	(11)
2011	377	136	(12)
2012	378	143	(13)
2013	384	151	(14)
Years 2014 to 2018, in Total	1,920	876	(87)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the years ended December 31, 2008, 2007 and 2006:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2008	2007	2006	2008	2007	2006
			(in millions)			
Service Cost	$ 100	$ 96	$ 97	$ 42	$ 42	$ 39
Interest Cost	249	235	231	113	104	102
Expected Return on Plan Assets	(336)	(340)	(335)	(111)	(104)	(94)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost (Credit)	1	-	(1)	-	-	-
Amortization of Net Actuarial Loss	37	59	79	9	12	22
Net Periodic Benefit Cost	51	50	71	80	81	96
Capitalized Portion	(16)	(14)	(21)	(25)	(25)	(27)
Net Periodic Benefit Cost Recognized as Expense	$ 35	$ 36	$ 50	$ 55	$ 56	$ 69

Estimated amounts expected to be amortized to net periodic benefit costs for AEP's plans during 2009 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 56	$ 46
Prior Service Cost	1	1
Transition Obligation	-	27
Total Estimated 2009 Pretax AOCI Amortization	$ 57	$ 74
Expected to be Recorded as		
Regulatory Asset	$ 46	$ 48
Deferred Income Taxes	4	9
Net of Tax AOCI	7	17
Total	$ 57	$ 74

The following table provides KPCo's net periodic benefit cost for the plans for the years ended December 31, 2008, 2007 and 2006:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2008	2007	2006	2008	2007	2006
	(in thousands)					
Benefit Costs	$ 995	$ 1,018	$ 1,435	$ 1,618	$ 1,706	$ 2,050

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2008	2007	2006	2008	2007	2006
Discount Rate	6.00%	5.75%	5.50%	6.20%	5.85%	5.65%
Expected Return on Plan Assets	8.00%	8.50%	8.50%	8.00%	8.00%	8.00%
Rate of Compensation Increase	5.90%	5.90%	5.90%	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2008 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, used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2008	2007
Initial	7.0%	7.5%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2012	2012

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	$ 20	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	196	(163)

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 company matching contributions. The matching contributions to the plan was 75% of the first 6% of eligible compensation contributed by the employee in 2008. Effective January 1, 2009, the match is 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for contributions to the plan totaled $1.6 million in 2008, $1.4 million in 2007 and $1.3 million in 2006.

7. BUSINESS SEGMENTS

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

8. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position 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 and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. 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 can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in 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, KPCo designates a hedging instrument as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), KPCo recognizes the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in net income during the period of change. 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) until the period the hedged item affects net income during the period of change. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

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. Realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in KPCo's Statements of Income. 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. Unrealized MTM gains and losses are recorded as regulatory assets (for losses) and regulatory liabilities (for gains).

Fair Value Hedging Strategies

At certain times, KPCo enters into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. KPCo records gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on the Statements of Income. During 2008, 2007 and 2006, KPCo recognized no hedge ineffectiveness related to these derivative transactions.

Cash Flow Hedging Strategies

KPCo enters into, and designates as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely monitors the potential impacts of commodity price changes, and where appropriate, enters into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives 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, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to energy commodities. At various times during 2008, 2007 and 2006, KPCo designated cash flow hedge relationships using these commodities and recognized immaterial amounts related to hedge ineffectiveness. However, there was no earnings impact because KPCo operates in a regulated jurisdiction.

KPCo enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo enters into various derivative instruments to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. KPCo reclassifies gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which the interest payments being hedged occur. At various times during 2007 and 2006, KPCo designated interest rate derivatives as cash flow hedges and recognized immaterial amounts related to hedge ineffectiveness. However, there was no earnings impact because KPCo operates in a regulated jurisdiction.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges at December 31, 2008:

	(in thousands)
Balance at December 31, 2005	$ (194)
Effective Portion of Changes in Fair Value	1,496
Impact Due to Changes in SIA	(106)
Reclasses from AOCI to Net Income	356
Balance at December 31, 2006	1,552
Effective Portion of Changes in Fair Value	(1,061)
Reclasses from AOCI to Net Income	(1,305)
Balance at December 31, 2007	(814)
Effective Portion of Changes in Fair Value	553
Reclasses from AOCI to Net Income	320
Balance at December 31, 2008	$ 59

The following table approximates net loss (gain) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2008 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. In addition, the following table summarizes the maximum length of time that the variability of future cash flows is being hedged. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes.

Portion Expected to be Reclassified to Net Income During the Next Twelve Months	Maximum Term for Exposure to Variability of Future Cash Flows
(in thousands)	(in months)
$ 502	$ 24

Credit Risk

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. KPCo limits its credit risk by maintaining stringent credit policies whereby KPCo assesses a counterparty's creditworthiness prior to transacting with them and continue to assess their creditworthiness on an ongoing basis. KPCo employees the use of 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 is exceeded in excess of an 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 also provide that the failure or inability to post collateral is sufficient cause for termination and liquidation of all positions.

FAIR VALUE MEASUREMENTS

SFAS 107 Fair Value Measurements

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current interest rates offered for instruments with similar maturities. 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 for KPCo at December 31, 2008 and 2007 are summarized in the following table:

	December 31,			
	2008		2007	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 418,555	$ 366,108	$ 448,373	$ 442,090

SFAS 157 Fair Value Measurements

As described in Note 2, KPCo completed the adoption of SFAS 157 effective January 1, 2009. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. The adoption of SFAS 157 had an immaterial impact on the financial statements. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3), b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, amounts for transition adjustment are recorded to beginning retained earnings. The impact of considering AEP's own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on KPCo's fair value measurements upon adoption.

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

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

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

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

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

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

The following table sets forth by level within the fair value hierarchy KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Contracts (a)	$ 3,443	$ 140,387	$ 2,561	$ (125,636)	$ 20,755
Cash Flow and Fair Value Hedges (a)	-	1,418	-	(302)	1,116
Dedesignated Risk Management Contracts (b)	-	-	-	2,749	2,749
Total Risk Management Assets	$ 3,443	$ 141,805	$ 2,561	$ (123,189)	$ 24,620
Liabilities:					
Risk Management Liabilities					
Risk Management Contracts (a)	$ 4,021	$ 132,087	$ 848	$ (126,370)	$ 10,586
Cash Flow and Fair Value Hedges (a)	-	544	-	(302)	242
DETM Assignment (c)	-	-	-	1,118	1,118
Total Risk Management Liabilities	$ 4,021	$ 132,631	$ 848	$ (125,554)	$ 11,946

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 12.

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

	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of January 1, 2008	$ (157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	95
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	-
Transfers in and/or out of Level 3 (b)	(192)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,967
Balance as of December 31, 2008	$ 1,713

(a) Included in revenues on KPCo's Statements of Income.
(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ 4,674	$ 11,258	$ 17,203
Deferred	4,097	5,691	2,596
Deferred Investment Tax Credits	(875)	(962)	(1,144)
Total Income Tax	$ 7,896	$ 15,987	$ 18,655

Shown below is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Net Income	$ 24,531	$ 32,470	$ 35,035
Income Taxes	7,896	15,987	18,655
Pretax Income	$ 32,427	$ 48,457	$ 53,690
Income Tax on Pretax Income at Statutory Rate (35%)	$ 11,349	$ 16,960	$ 18,791
Increase (Decrease) in Income Tax resulting from the following items:			
Depreciation	1,169	1,223	1,669
Allowance for Funds Used During Construction	(872)	(661)	(606)
Removal Costs	(4,110)	(1,766)	(1,361)
Investment Tax Credits, Net	(875)	(962)	(1,144)
State and Local Income Taxes	1,072	736	1,070
Other	163	457	236
Total Income Taxes	$ 7,896	$ 15,987	$ 18,655
Effective Income Tax Rate	24.4%	33.0%	34.7%

The following table shows the elements of the net deferred tax liability and the significant temporary differences:

	December 31, 2008	2007
	(in thousands)	
Deferred Tax Assets	$ 56,519	$ 35,037
Deferred Tax Liabilities	(312,433)	(280,667)
Net Deferred Tax Liabilities	$ (255,914)	$ (245,630)
Property Related Temporary Differences	$ (203,951)	$ (188,213)
Amounts Due From Customers For Future Federal Income Taxes	(27,299)	(25,794)
Deferred State Income Taxes	(29,694)	(27,325)
Deferred Income Taxes on Other Comprehensive Loss	(32)	438
Deferred Fuel and Purchased Power	54	(1,617)
Accrued Pensions	8,959	(3,521)
All Other, Net	(3,951)	402
Net Deferred Tax Liabilities	$ (255,914)	$ (245,630)

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

KPCo and other AEP Subsidiaries are no longer subject to U.S. federal examination for years before 2000. KPCo and other AEP Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that are being pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

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

Prior to the adoption of FIN 48, KPCo recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48 on January 1, 2007, KPCo began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation. The impact of this interpretation was an unfavorable adjustment to the 2007 opening balance of retained earnings of $786 thousand. In 2008, KPCo reported $303 thousand of interest expense and $1.9 million of interest income. In 2007, KPCo reported $55 thousand of interest expense and reversed $926 thousand of prior period interest expense. KPCo had approximately $1.7 million for the receipt of interest accrued at December 31, 2008 and $788 thousand and $1.3 million for the payment of interest and penalties accrued at December 31, 2008 and 2007, respectively.

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

	2008	2007
	(in thousands)	
Balance at January 1,	$ 2,205	$ 3,413
Increase - Tax Positions Taken During a Prior Period	-	1
Decrease - Tax Positions Taken During a Prior Period	(113)	(1,796)
Increase - Tax Positions Taken During the Current Year	1,301	587
Decrease - Tax Positions Taken During the Current Year	(144)	-
Increase - Settlements with Taxing Authorities	96	-
Decrease - Lapse of the Applicable Statute of Limitations	-	-
Balance at December 31,	$ 3,345	$ 2,205

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $881 thousand and $936 thousand in 2008 and 2007, respectively. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

Several tax bills and other legislation with tax-related sections were enacted in 2006 and 2007, including the Pension Protection Act of 2006, the Tax Relief and Health Care Act of 2006, the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007 and the Energy Independence and Security Act of 2007. The tax law changes enacted in 2006 and 2007 did not materially affect KPCo's net income, cash flows or financial condition.

The Economic Stimulus Act of 2008 was signed into law by the President in February 2008. It provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a material favorable cash flow benefit of approximately $8 million.

In October 2008, the Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law. The 2008 Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits, and energy efficient commercial building deductions. Management has evaluated the impact of the law change and the application of the law change will not materially impact KPCo's net income, cash flows or financial condition.

In February 2009, the American Recovery and Reinvestment Tax Act of 2009 (the 2009 Act) was signed into law. The 2009 Act extended the bonus depreciation deduction for one year and provides for a long-term extension of the renewable production tax credit for wind energy and other properties. The 2009 Act also establishes a new investment tax credit for the manufacture of advanced energy property as well as appropriations for advanced energy research projects, carbon capture and storage and gridSMART technology. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income or financial condition, but is expected to have a positive material impact on cash flows.

State Tax Legislation

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

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

In March 2008, the Governor of West Virginia signed legislation providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management has evaluated the impact of the law change and the application of the law change will not materially impact KPCo's net income, cash flows or financial condition.

10. LEASES

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

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

	Years Ended December 31,		
	2008	2007	2006
Lease Rental Costs		(in thousands)	
Net Lease Expense on Operating Leases	$ 2,250	$ 2,405	$ 2,079
Amortization of Capital Leases	971	1,141	1,207
Interest on Capital Leases	102	140	116
Total Lease Rental Costs	$ 3,323	$ 3,686	$ 3,402

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 Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on KPCo's Balance Sheets.

	December 31,	
	2008	2007
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ -	$ 22
Other	3,974	5,261
Total Property, Plant and Equipment Under Capital Leases	3,974	5,283
Accumulated Amortization	2,152	3,039
Net Property, Plant and Equipment Under Capital Leases	$ 1,822	$ 2,244
Obligations Under Capital Leases		
Noncurrent Liability	$ 1,045	$ 1,272
Liability Due Within One Year	777	972
Total Obligations Under Capital Leases	$ 1,822	$ 2,244

Future minimum lease payments consisted of the following at December 31, 2008:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2009	$ 804	$ 2,032
2010	588	1,803
2011	446	7,451
2012	15	98
2013	15	98
Later Years	18	432
Total Future Minimum Lease Payments	$ 1,886	$ 11,914
Less Estimated Interest Element	64	
Estimated Present Value of Future Minimum Lease Payments	$ 1,822	

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, KPCo will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. As a result, the unamortized value of this equipment of $6 million is reflected in KPCo's future minimum lease payments for 2011. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into replacement leasing arrangements for the equipment affected by this notification prior to the termination date of 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At December 31, 2008, the maximum potential loss for these lease agreements was approximately $613 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

11. FINANCING ACTIVITIES

Long-term Debt

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

The following details long-term debt outstanding as of December 31, 2008 and 2007:

Type of Debt	Maturity	Weighted Average Interest Rate at December 31, 2008	Interest Rate Ranges at December 31, 2008	Interest Rate Ranges at December 31, 2007	Outstanding at December 31, 2008	Outstanding at December 31, 2007
					(in thousands)	
Senior Unsecured Notes	2008-2032	5.93%	5.625%-6.00%	5.625%-6.45%	$ 400,000	$ 430,000
Notes Payable – Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Unamortized Discount					(1,445)	(1,627)
Total Long-term Debt					418,555	448,373
Less: Long-term Debt Due Within One Year					-	30,000
Long-term Debt					$ 418,555	$ 418,373

At December 31, 2008 future annual long-term debt payments are as follows:

	2009	2010	2011	2012	2013	After 2013	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ -	$ -	$ 420,000	$ 420,000
Unamortized Discount							(1,445)
Total Long-term Debt							$ 418,555

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of December 31, 2008 and 2007 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2008 and 2007 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2008	$ 142,416	$ -	$ 54,536	$ -	$ 131,399	$ 250,000
2007	164,913	181,970	59,104	115,727	19,153	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, 2008, 2007 and 2006 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2008	5.47%	2.28%	-%	-%	3.42%	-%
2007	5.92%	5.29%	5.94%	5.16%	5.50%	5.58%
2006	5.41%	3.32%	5.12%	4.19%	4.74%	4.97%

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, in 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, 2008, 2007 and 2006:

	Years Ended December 31, 2008	2007	2006
		(in thousands)	
Interest Expense	$ 1,893	$ 2,494	$ 1,065
Interest Income	-	1,614	30

Dividend Restrictions

Under the Federal Power Act, KPCo is restricted from paying dividends out of stated capital.

Credit Facilities

In April 2008, KPCo and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of December 31, 2008, there were no outstanding amounts for KPCo under either facility.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate AEP Credit's cash collections.

In October 2008, AEP renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables from AEP Credit. This agreement will expire in October 2009. AEP intends to extend or replace the sale of receivables agreement. The previous sale of receivables agreement, which expired in October 2008 and was extended until October 2009, provided a commitment of $650 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Under the previous sale of receivable agreement, the commitment increased to $700 million for the months of August and September to accommodate seasonal demand. At December 31, 2008, $650 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts. AEP Credit purchases accounts receivable through a purchase agreement with KPCo.

Comparative accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2008	2007	2006
		($ in millions)	
Proceeds from Sale of Accounts Receivable	$ 7,717	$ 6,970	$ 6,849
Loss on Sale of Accounts Receivable	$ 20	$ 33	$ 31
Average Variable Discount Rate	3.19%	5.39%	5.02%

	December 31, 2008	2007
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 118	$ 71
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	116	68
Retained Interest if 20% Adverse Change in Uncollectible Accounts	114	66

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	December 31, 2008	2007
	(in millions)	
Customer Accounts Receivable Retained	$ 569	$ 730
Accrued Unbilled Revenues Retained	449	379
Miscellaneous Accounts Receivable Retained	90	60
Allowance for Uncollectible Accounts Retained	(42)	(52)
Total Net Balance Sheet Accounts Receivable	1,066	1,117
Customer Accounts Receivable Securitized	650	507
Total Accounts Receivable Managed	$ 1,716	$ 1,624
Net Uncollectible Accounts Written Off	$ 37	$ 24

Customer accounts receivable retained and securitized for the electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $22 million and $30 million at December 31, 2008 and 2007, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

Under the factoring 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 financing costs, its uncollectible accounts experience receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the KPCo's Statements of Income.

KPCo's factored accounts receivable and accrued unbilled revenues were $55.8 million and $41.4 million as of December 31, 2008 and 2007, respectively.

KPCo paid fees to AEP Credit for factoring customer accounts receivable of $3.2 million, $3.8 million and $3.4 million for the years ended December 31, 2008, 2007 and 2006, respectively.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

AEP Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's member load ratio, which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

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

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). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

In November 2005, AEP filed with the FERC a proposed amendment to the SIA to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method causes such profits to be allocated generally on the basis of the zone in which the underlying transactions occur or originate. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006 and was approved as filed effective April 1, 2006.

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

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

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES, and other revenues for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	2007	2006
Related Party Revenues		(in thousands)	
Sales to AEP Power Pool	$ 62,642	$ 56,708	$ 57,921
Direct Sales to West Affiliates	3,521	3,738	4,801
Natural Gas Contracts with AEPES	(133)	(197)	(4,698)
Other	219	302	263
Total Revenues	$ 66,249	$ 60,551	$ 58,287

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2008, 2007 and 2006:

	Years Ended December 31,		
	2008	**2007**	**2006**
Related Party Purchases		**(in thousands)**	
Purchases from AEP Power Pool	$ 127,669	$ 96,997	$ 99,166
Direct Purchases from East Affiliates	106,256	88,051	92,881
Direct Purchases from West Affiliates	454	351	33
Total Purchases	$ 234,379	$ 185,399	$ 192,080

The above summarized related party revenues and expenses are reported as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on KPCo's Statements of Income.

AEP System Transmission Pool

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 Equalization Agreement (TEA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

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

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

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TEA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's member load ratio.

KPCo's net credits as allocated under the TEA during the years ended December 31, 2008, 2007 and 2006 were $2 million, $800 thousand and $2 million, respectively, and were recorded in Other Operation on KPCo's Statements of Income.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. 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 AEP West companies.

Natural Gas Contracts with DETM

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Beginning in 2007, PSO and SWEPCo were allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies and PSO and SWEPCo. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. KPCo's risk management liabilities related to DETM at December 31, 2008 and 2007 were $1.1 million and $1.9 million, respectively.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with those two parties to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. KPCo's related purchases of gas managed by AEPES were $257 thousand, $930 thousand and $398 thousand for the years ended December 31, 2008, 2007 and 2006, respectively. These purchases are reflected in Purchased Electricity for Resale on KPCo's Statements of Income.

Unit Power Agreements (UPA)

A unit power agreement 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. 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 unit power agreement 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 has agreed to pay 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 unit power agreement ends in December 2022. See "Affiliated Revenues and Purchases" section of this note.

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 costs of $9 thousand, $80 thousand and $68 thousand in 2008, 2007 and 2006, respectively, for urea transloading provided by I&M. These costs were recorded as fuel expense or operation expense.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its balance sheet the cost of performing the services, then transfers the cost to the affiliate for reimbursement. KPCo recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $1.2 million, $167 thousand and $181 thousand for the years ended December 31, 2008, 2007 and 2006, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of affiliate's 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 records these costs or reimbursements as costs or reduction of costs, respectively, in Fuel on its 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,	
	2008	2007
Billing Company	(in thousands)	
APCo	$ 274	$ 90
OPCo	332	183

AEP Power Pool Purchases from OVEC

Beginning in 2006, the AEP Power Pool began purchasing power from OVEC as part of wholesale marketing and risk management activity. These purchases are reflected in Electric Generation, Transmission and Distribution revenues in KPCo's Statements of Income. The agreement expired in May 2008 and subsequently ended in December 2008. KPCo recorded $4 million and $2 million for the years ended December 31, 2008 and 2007, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2008, 2007 and 2006 as shown in the following table:

	Years Ended December 31,		
	2008	2007	2006
Companies		(in thousands)	
I&M to KPCo	$ 444	$ -	$ -
KPCo to APCo	-	-	191
OPCo to KPCo	-	133	-

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2008, 2007 and 2006 as shown in the following table:

	APCO	CSPCo	I&M	KGPCo	OPCo	PSO	SWEPCo	TCC	WPCo	Total
Sales					(in thousands)					
2008	$ 354	$ 11	$ 16	$ 6	$ 121	$ -	$ 2	$ 33	$ -	$ 543
2007	345	38	21	10	124	85	7	-	66	696
2006	2,178	75	40	11	254	28	-	3	9	2,598
Purchases										
2008	$ 112	$ -	$ 15	$ -	$ 95	$ -	$ -	$ -	$ -	$ 222
2007	518	6	4	1	197	-	-	-	5	731
2006	3,206	1	18	-	504	-	-	-	3	3,732

The amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

Global Borrowing Notes

AEP issued long-term debt, a portion of which was loaned to KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's Balance Sheets. AEP pays the interest on the global notes, but KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Other in the Current Liabilities section of KPCo's balance sheets. KPCo participated in the global borrowing arrangement during the reporting periods.

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 bases 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. Billings are capitalized or expensed depending on the nature of the services rendered.

Variable Interest Entities

FIN 46R is a consolidation model that considers risk absorption of a variable interest entity (VIE), also referred to as variability. Entities are required to consolidate a VIE when it is determined that they are the primary beneficiary of that VIE, as defined by FIN 46R. In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of variability of the VIE KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, the power to direct the VIE and other factors. Management believes that the significant assumptions and judgments were applied consistently and that there are no other reasonable judgments or assumptions that would result in a different conclusion. There have been no changes to the reporting of VIEs in the financial statements where it is concluded that KPCo is the primary beneficiary. In addition, KPCo has not provided financial or other support that was not previously contractually required to any VIE.

As of December 31, 2008, KPCo holds a significant variable interest in AEPSC and AEGCo. AEPSC provides certain managerial and professional services to KPCo. AEP is the sole equity owner of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo at AEPSC's cost. KPCo has not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and KPCo that could require additional financial support from KPCo or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo is exposed to losses to the extent it cannot recover the costs of AEPSC through its normal business operations. KPCo is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. 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. Total billings from AEPSC for the years ended December 31, 2008 and 2007 were $46.4 million and $35.3 million, respectively. The carrying amount of liabilities associated with AEPSC for the years ended December 31, 2008 and 2007 were $4.7 million and $5.1 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, leases a 50% interest in Rockport Plant Unit 2 and owns 100% of the Lawrenceburg Generating Station. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. KPCo has no involvement with AEGCo's interest in the Lawrenceburg Generating Station. 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 the nature of the AEP Power Pool, there is a sharing of the cost of Rockport Plant such that no member of the AEP Power Pool is the primary beneficiary of AEGCo's Rockport Plant. 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, 2008 and 2007 were $106.3 million and $88.8 million, respectively. The carrying amount of liabilities associated with AEGCo for the years ended December 31, 2008 and 2007 were $9.4 million and $7.7 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

13. 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 table provides the annual composite depreciation rates by functional class:

2008	Regulated					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)
Production	$ 533,998	$ 177,679	3.5%	40-50		$ -	$ -	-	-
Transmission	431,835	135,955	1.6%	25-75		-	-	-	-
Distribution	528,711	146,009	3.4%	11-75		-	-	-	-
CWIP	46,650	(7,936)	N.M.	N.M.		-	-	-	-
Other	59,994	24,684	8.1%	N.M.		5,491	177	N.M.	N.M.
Total	$ 1,601,188	$ 476,391				$ 5,491	$ 177		

2007	Regulated				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)
Production	$ 482,653	$ 168,806	3.8%	40-50	$ -	$ -	-	-
Transmission	402,259	131,115	1.7%	25-75	-	-	-	-
Distribution	502,486	136,528	3.4%	11-75	-	-	-	-
CWIP	46,439	(1,463)	N.M.	N.M.	-	-	-	-
Other	56,173	21,867	8.7%	N.M.	5,492	175	N.M.	N.M.
Total	$ 1,490,010	$ 456,853			$ 5,492	$ 175		

2006	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)
Production	3.8%	40-50	-	-
Transmission	1.7%	25-75	-	-
Distribution	3.4%	11-75	-	-
Other	9.6%	N.M.	N.M.	N.M.

N.M. = 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 SFAS 143 "Accounting for Asset Retirement Obligations" and FIN 47 "Accounting for Conditional Asset Retirement Obligations" for the retirement of ash ponds 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 2008 and 2007 aggregate carrying amounts of ARO for KPCo:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2008	$ 944	$ 52	$ -	$ (590)	$ 2,869	$ 3,275
2007	1,175	63	-	(294)	-	944

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, 2008	2007	2006
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 1,012	$ 260	$ 241
Allowance for Borrowed Funds Used During Construction	1,701	595	656

14. ~~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:

	2008 Quarterly Periods Ended March 31	June 30	September 30	December 31
		(in thousands)		
Revenues	$ 167,290	$ 147,051	$ 188,872	$ 162,347 (a)
Operating Income	21,557	21,528	16,770	3,992 (a)
Net Income (Loss)	11,144	10,930	7,451	(4,994)(a)

	2007 Quarterly Periods Ended March 31	June 30	September 30	December 31
		(in thousands)		
Revenues	$ 154,096	$ 134,530	$ 152,200	$ 147,174
Operating Income	30,535	7,702	16,815	19,788
Net Income	15,211	1,230	6,485	9,544

(a) See "Allocation of Off-system Sales Margins" section of Note 3 for discussion of the financial statement impact of the FERC's November 2008 order related to the SIA.

There were no significant events in the fourth quarter of 2007.

Kentucky Power Company

2008 First Quarter Report

Financial Statements

AEP AMERICAN® ELECTRIC POWER

TABLE OF 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
AEP or Parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
GAAP	Accounting Principles Generally Accepted in the United States of America.
IRS	Internal Revenue Service.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over the counter.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."

Term	Meaning
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.

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

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

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

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Three Months Ended March 31, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 50,450	$ 208,750	$ 108,899	$ 1,552	$ 369,651
FIN 48 Adoption, Net of Tax			(786)		(786)
Common Stock Dividends			(5,000)		(5,000)
TOTAL					363,865
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,100				(2,042)	(2,042)
NET INCOME			15,211		15,211
TOTAL COMPREHENSIVE INCOME					13,169
MARCH 31, 2007	$ 50,450	$ 208,750	$ 118,324	$ (490)	$ 377,034
DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(2,500)		(2,500)
TOTAL					384,104
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,258				(2,335)	(2,335)
NET INCOME			11,144		11,144
TOTAL COMPREHENSIVE INCOME					8,809
MARCH 31, 2008	$ 50,450	$ 208,750	$ 136,862	$ (3,149)	$ 392,913

See Condensed Notes to Condensed Financial Statements.

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

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

See Condensed Notes to Condensed Financial Statements.

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

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 40,305	$ 19,153
Accounts Payable:		
General	32,155	32,603
Affiliated Companies	19,451	29,437
Long-term Debt Due Within One Year – Nonaffiliated	30,000	30,000
Risk Management Liabilities	30,089	10,310
Customer Deposits	14,954	14,422
Accrued Taxes	16,915	16,875
Regulatory Liability for Over-Recovered Fuel Costs	1,299	-
Other	18,342	31,909
TOTAL	203,510	184,709
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,419	398,373
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	11,159	9,699
Deferred Income Taxes	244,087	240,858
Regulatory Liabilities and Deferred Investment Tax Credits	45,943	46,434
Deferred Credits and Other	25,211	24,379
TOTAL	744,819	739,743
TOTAL LIABILITIES	948,329	924,452
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	136,862	128,583
Accumulated Other Comprehensive Income (Loss)	(3,149)	(814)
TOTAL	392,913	386,969
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,341,242	$ 1,311,421

See Condensed Notes to Condensed Financial Statements.

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

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

See Condensed Notes to Condensed Financial Statements.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Income Taxes
8. Financing Activities

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations, financial position and cash flows for the interim periods. The results of operations for the three months ended March 31, 2008 are not necessarily indicative of results that may be expected for the year ending December 31, 2008. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2007 financial statements and notes thereto, which are included in KPCo's 2007 Annual Report.

Reclassifications

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

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of new pronouncements issued or implemented in 2008 and standards issued but not implemented that management has determined relate to KPCo's operations.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period.

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

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

In February 2008, the FASB issued FSP FAS 157-2 "Effective Date of FASB Statement No. 157" which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

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

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

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

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

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

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

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

The following table sets forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of March 31, 2008

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

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 16 in the 2007 Annual Report.

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

		Net Risk Management Assets (Liabilities)
		(in thousands)
Balance as of January 1, 2008	$	(157)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)		(131)
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements		-
Transfers in and/or out of Level 3 (b)		(210)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		293
Balance as of March 31, 2008	$	(205)

(a) Included in revenues on KPCo's Condensed Statement of Income for the Three Months Ended March 31, 2008.

(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

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

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

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

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

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

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard is intended to improve upon the existing disclosure framework in SFAS 133.

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

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

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

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

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

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

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

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

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

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

For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the March 31, 2008 balance sheet, KPCo netted $1.8 million of cash collateral received from third parties against short-term and long-term risk management assets and $2.7 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, liabilities and equity, emission allowances, leases, insurance, subsequent events and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

3. RATE MATTERS

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

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. The KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable to KPCo, it is possible that the AG or another intervenor could challenge KPCo's existing surcharges, which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, annual Rockport Plant capacity surcharge, merger surcredit and off-system sales credit rider. These surcharges are currently producing net annual revenues of approximately $10 million. The KPSC has asked interested parties to brief the issue in KPCo's outstanding fuel cost proceeding. The AG stated that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that it has the authority to provide for surcharges and surcredits until the Court of Appeals rules. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time. KPCo's exposure is indeterminable at this time since it is not known whether a final adverse appeal could result in a refund of prior amounts collected, which would have an adverse effect on future results of operations and cash flows.

2008 Fuel Cost Reconciliation

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

FERC Rate Matters

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC's direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving AEP and ultimately its internal load customers to make up the short fall in revenues.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. As a result, SECA ratepayers have been willing to engage with AEP in settlement discussions. AEP has been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

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

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

If the FERC adopts the ALJ's decision and/or AEP cannot settle the remaining unsettled claims within the amount reserved for refunds, it will have an adverse effect on future results of operations and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $35 million is adequate to cover all remaining settlements. KPCo's portion of the reserve is $3 million. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if such are necessary.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates and the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP had requested rehearing of this order, which the FERC denied. AEP filed a Petition for Review of the FERC orders in this case in February 2008 in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, results of operations and cash flows.

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

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argues the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. Should this effort be successful, KPCo would reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2007 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to March 31, 2008, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Operating Lease

KPCo leases certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $2 million as of March 31, 2008.

CONTINGENCIES

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. Management believes the action is without merit and intends to defend against the claims.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed and argued before the U.S. Supreme Court in February 2008. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. Management asserted claims against certain companies that sold power to KPCo and other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities.

5. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

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

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

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

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

6. BUSINESS SEGMENTS

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

7. INCOME TAXES

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

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

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, KPCo and other AEP subsidiaries have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2003 and have issues that will be pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

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

State Tax Legislation

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

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

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

8. FINANCING ACTIVITIES

Lines of Credit

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of March 31, 2008 and December 31, 2007 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the three months ended March 31, 2008 are described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of March 31, 2008	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 40,595	$ -	$ 20,944	$ -	$ 40,305	$ 250,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the three months ended March 31, 2008 and 2007 are summarized in the following table:

	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates For Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2008	5.37%	3.39%	-%	-%	4.09%	-%
2007	5.43%	5.30%	-%	-%	5.34%	-%

Credit Facilities

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

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Kentucky Power Company

2008 Second Quarter Report

Financial Statements

AMERICAN ELECTRIC POWER

TABLE OF CONTENTS | Page

GLOSSARY OF TERMS

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

Term	Meaning
AEP or Parent	American Electric Power Company, Inc.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CAA	Clean Air Act.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
FSP	FASB Staff Position.
FTR	Financial Transmission Right.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IRS	Internal Revenue Service.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
NO_x	Nitrogen Oxide.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OTC	Over-the-counter.
PUCT	Public Utility Commission of Texas.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."

Term	Meaning
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended 2008	Three Months Ended 2007	Six Months Ended 2008	Six Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 128,152	$ 123,280	$ 275,211	$ 263,766
Sales to AEP Affiliates	18,729	11,162	38,782	24,623
Other	170	88	348	237
TOTAL	147,051	134,530	314,341	288,626
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	14,262	40,121	63,473	78,425
Purchased Electricity for Resale	5,706	3,457	9,472	6,762
Purchased Electricity from AEP Affiliates	60,262	43,578	114,452	86,835
Other Operation	13,877	14,632	29,385	30,518
Maintenance	16,603	10,337	26,523	18,547
Depreciation and Amortization	11,941	11,730	23,899	23,526
Taxes Other Than Income Taxes	2,872	2,973	4,052	5,776
TOTAL	125,523	126,828	271,256	250,389
OPERATING INCOME	21,528	7,702	43,085	38,237
Other Income (Expense):				
Interest Income	553	72	1,841	184
Allowance for Equity Funds Used During Construction	333	24	677	38
Interest Expense	(7,496)	(7,201)	(14,351)	(14,212)
INCOME BEFORE INCOME TAX EXPENSE (CREDIT)	14,918	597	31,252	24,247
Income Tax Expense (Credit)	3,988	(633)	9,178	7,806
NET INCOME	$ 10,930	$ 1,230	$ 22,074	$ 16,441

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

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S
EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 50,450	$ 208,750	$ 108,899	$ 1,552	$ 369,651
FIN 48 Adoption, Net of Tax			(786)		(786)
Common Stock Dividends			(8,999)		(8,999)
TOTAL					359,866
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,758				3,265	3,265
NET INCOME			16,441		16,441
TOTAL COMPREHENSIVE INCOME					19,706
JUNE 30, 2007	$ 50,450	$ 208,750	$ 115,555	$ 4,817	$ 379,572
DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(5,000)		(5,000)
TOTAL					381,604
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,796				(3,336)	(3,336)
NET INCOME			22,074		22,074
TOTAL COMPREHENSIVE INCOME					18,738
JUNE 30, 2008	$ 50,450	$ 208,750	$ 145,292	$ (4,150)	$ 400,342

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
June 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 600	$ 727
Accounts Receivable:		
Customers	25,089	20,196
Affiliated Companies	5,794	15,984
Accrued Unbilled Revenues	2,267	2,904
Miscellaneous	108	178
Allowance for Uncollectible Accounts	(1,108)	(1,071)
Total Accounts Receivable	32,150	38,191
Fuel	11,119	8,338
Materials and Supplies	11,939	11,758
Risk Management Assets	41,852	12,121
Regulatory Asset for Under-Recovered Fuel Costs	12,613	4,426
Prepayments and Other	6,361	4,024
TOTAL	116,634	79,585
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	483,686	482,653
Transmission	404,962	402,259
Distribution	513,872	502,486
Other	63,145	61,665
Construction Work in Progress	78,064	46,439
Total	1,543,729	1,495,502
Accumulated Depreciation and Amortization	471,008	457,028
TOTAL - NET	1,072,721	1,038,474
OTHER NONCURRENT ASSETS		
Regulatory Assets	129,180	124,828
Long-term Risk Management Assets	22,738	14,826
Deferred Charges and Other	51,203	53,708
TOTAL	203,121	193,362
TOTAL ASSETS	$ 1,392,476	$ 1,311,421

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
June 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 48,435	$ 19,153
Accounts Payable:		
General	33,119	32,603
Affiliated Companies	24,870	29,437
Long-term Debt Due Within One Year – Nonaffiliated	30,000	30,000
Risk Management Liabilities	48,746	10,310
Customer Deposits	15,686	14,422
Accrued Taxes	10,692	16,875
Other	27,677	31,909
TOTAL	239,225	184,709
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,465	398,373
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	17,880	9,699
Deferred Income Taxes	250,750	240,858
Regulatory Liabilities and Deferred Investment Tax Credits	41,009	46,434
Deferred Credits and Other	24,805	24,379
TOTAL	752,909	739,743
TOTAL LIABILITIES	992,134	924,452
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	145,292	128,583
Accumulated Other Comprehensive Income (Loss)	(4,150)	(814)
TOTAL	400,342	386,969
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,392,476	$ 1,311,421

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Six Months Ended June 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 22,074	$ 16,441
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	23,899	23,526
Deferred Income Taxes	7,866	(1,042)
Allowance for Equity Funds Used During Construction	(677)	(38)
Mark-to-Market of Risk Management Contracts	3,309	2,406
Change in Other Noncurrent Assets	(2,106)	(789)
Change in Other Noncurrent Liabilities	(1,599)	(202)
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	6,041	4,650
Fuel, Materials and Supplies	(2,962)	(3,346)
Accounts Payable	1,462	(11,273)
Accrued Taxes, Net	(5,369)	1,673
Fuel Over/Under-Recovery, Net	(8,187)	7,642
Other Current Assets	(3,150)	283
Other Current Liabilities	(3,373)	(2,398)
Net Cash Flows from Operating Activities	37,228	37,533
INVESTING ACTIVITIES		
Construction Expenditures	(61,434)	(27,771)
Proceeds from Sales of Assets	202	361
Net Cash Flows Used for Investing Activities	(61,232)	(27,410)
FINANCING ACTIVITIES		
Change in Advances from Affiliates, Net	29,282	(917)
Principal Payments for Capital Lease Obligations	(405)	(443)
Dividends Paid on Common Stock	(5,000)	(8,999)
Net Cash Flows from (Used for) Financing Activities	23,877	(10,359)
Net Decrease in Cash and Cash Equivalents	(127)	(236)
Cash and Cash Equivalents at Beginning of Period	727	702
Cash and Cash Equivalents at End of Period	$ 600	$ 466
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 14,536	$ 14,388
Net Cash Paid for Income Taxes	603	821
Noncash Acquisitions Under Capital Leases	126	394
Construction Expenditures Included in Accounts Payable at June 30,	6,648	3,419

See Condensed Notes to Condensed Financial Statements.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Income Taxes
8. Financing Activities

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the results of operations, financial position and cash flows for the interim periods. The results of operations for the three and six months ended June 30, 2008 are not necessarily indicative of results that may be expected for the year ending December 31, 2008. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2007 financial statements and notes thereto, which are included in KPCo's 2007 Annual Report.

Reclassifications

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

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of new pronouncements issued or implemented in 2008 and standards issued but not implemented that management has determined relate to KPCo's operations.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period.

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

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

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

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

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

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

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

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

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

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

The following table sets forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of June 30, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 7,613	$ 268,060	$ 2,300	$ (217,114)	$ 60,859
Cash Flow and Fair Value Hedges (a)	-	1,603	-	(1,061)	542
Dedesignated Risk Management Contracts (b)	-	-	-	3,189	3,189
Total Risk Management Assets	$ 7,613	$ 269,663	$ 2,300	$ (214,986)	$ 64,590
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 8,109	$ 260,610	$ 6,270	$ (216,302)	$ 58,687
Cash Flow and Fair Value Hedges (a)	-	7,479	-	(1,061)	6,418
DETM Assignment (c)	-	-	-	1,521	1,521
Total Risk Management Liabilities	$ 8,109	$ 268,089	$ 6,270	$ (215,842)	$ 66,626

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 13 in the 2007 Annual Report.

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:

		Net Risk Management Assets (Liabilities) (in thousands)
Balance as of April 1, 2008	$	(205)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)		(112)
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements		-
Transfers in and/or out of Level 3 (b)		(467)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(3,186)
Balance as of June 30, 2008	$	(3,970)

		Net Risk Management Assets (Liabilities) (in thousands)
Balance as of January 1, 2008	$	(157)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)		(89)
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)		-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income		-
Purchases, Issuances and Settlements		-
Transfers in and/or out of Level 3 (b)		(13)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)		(3,711)
Balance as of June 30, 2008	$	(3,970)

(a) Included in revenues on KPCo's Condensed Statement of Income.
(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

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

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

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

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

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

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard is intended to improve upon the existing disclosure framework in SFAS 133.

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

SFAS 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162)

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

SFAS 162 is effective 60 days after the SEC approves the Public Company Accounting Oversight Board's amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." Management expects the adoption of this standard will have no impact on the financial statements. KPCo will adopt SFAS 162 when it becomes effective.

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

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. KPCo adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $562 thousand ($365 thousand, net of tax) to beginning earnings.

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

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after December 15, 2007.

KPCo adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on the financial statements.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS 142, "Goodwill and Other Intangible Assets." The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

SFAS 142-3 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. Early adoption is prohibited. Upon adoption, the guidance within SFAS 142-3 will be prospectively applied to intangible assets acquired after the effective date. Management expects that the adoption of this standard will have an immaterial impact on the financial statements. KPCo will adopt SFAS 142-3 effective January 1, 2009.

FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)

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

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

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

For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the June 30, 2008 balance sheet, KPCo netted \$5.1 million of cash collateral received from third parties against short-term and long-term risk management assets and \$4.3 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, hedge accounting, trading inventory and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

3. RATE MATTERS

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

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. The KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that it has the authority to provide for surcharges and surcredits until the Court of Appeals rules. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time. KPCo's exposure is indeterminable at this time since it is not known whether a final adverse appeal could result in a refund of prior amounts collected, which would have an adverse effect on future results of operations and cash flows.

2008 Fuel Cost Reconciliation

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM's implementation of marginal loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo's semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM beginning May 2008. Therefore, in the second quarter of 2008, KPCo recorded $13 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through June 2008 of which $7 million related to 2007.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC's direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load customers to make up the short fall in revenues.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. As a result, SECA ratepayers have been willing to engage with AEP in settlement discussions. AEP has been engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

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

Completed and in-process settlements cover $107 million of the $220 million of SECA revenues and will consume about $7 million of the reserve for refund, leaving approximately $113 million of contested SECA revenues and $35 million of refund reserves.

If the FERC adopts the ALJ's decision and/or AEP cannot settle the remaining unsettled claims within the amount reserved for refunds, it will have an adverse effect on future results of operations and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $35 million is adequate to cover all remaining settlements. KPCo's portion of the reserve is $3 million. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if such are necessary.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates and the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP had requested rehearing of this order, which the FERC denied. In February 2008, AEP filed a Petition for

Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, results of operations and cash flows.

The AEP East companies filed for and in 2006 obtained increases in its wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 85% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future results of operations and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 15% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argues the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. Should this effort be successful, earnings could benefit for a certain period due to regulatory lag; however, AEP East companies would reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in additional annual revenues for AEP of approximately $9 million from nonaffiliated customers within PJM. AEP requested an effective date of October 1, 2008. Management is unable to predict the outcome of this filing.

Allocation of Off-system Sales Margins

In August 2007, the OCC issued an order adopting the ALJ's recommendation that the allocation of system sales/trading margins is a FERC jurisdictional issue. In October 2007, the OCC orally directed the OCC staff to explore filing a complaint at FERC alleging the allocation of off-system sales margins to PSO is improper. In June 2008, the ALJ issued a final recommendation and incorporated the prior finding that the OCC lacked authority to review AEP's application of a FERC-approved methodology. The OCC is scheduled to consider the final recommendation in August 2008.

In December 2007, some cities served by TNC requested the PUCT to initiate, or order TNC to initiate a proceeding at the FERC to determine if TNC misapplied its tariff. In January 2008, TNC filed a response with the PUCT recommending the cities' request be denied.

To date, no claim has been asserted at the FERC. Although management cannot predict if a complaint will be filed at the FERC, management believes the allocations were in accordance with the then-existing FERC-approved allocation agreement and additional off-system sales margins should not be retroactively reallocated to the AEP West companies. A reallocation of off-system sales margins from the AEP East companies to the AEP West companies could result in an adverse effect on future results of operations and cash flows for KPCo.

FERC Market Power Mitigation

The FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that the FERC should further investigate whether AEP continues to pass the FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also urged the FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with the FERC's guidelines, and continue to demonstrate lack of market power.

Management is unable to predict the outcome of this proceeding; however, if a further investigation by the FERC limited AEP's ability to sell power at market based rates in PJM, it would result in an adverse effect on future off-system sales margins, results of operations and cash flows.

4. <u>COMMITMENTS, GUARANTEES AND CONTINGENCIES</u>

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2007 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

<u>*Contracts*</u>

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to June 30, 2008, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

<u>*Master Operating Lease*</u>

KPCo leases certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $2 million as of June 30, 2008.

CONTINGENCIES

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. Management believes the action is without merit and intends to defend against the claims.

Clean Air Act Interstate Rule

In 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that required further reductions in SO_2 and NO_x emissions and assists states developing new state implementation plans to meet 1997 national ambient air quality standards (NAAQS). CAIR reduces regional emissions of SO_2 and NO_x (which can be transformed into PM and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals vacated the CAIR and remanded the rule to the Federal EPA. We are unable to predict how the Federal EPA will respond to the remand which could be stayed or appealed to the U.S. Supreme Court.

KPCo did not purchase any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to the AEP System's facilities under the Acid Rain Program and the NO_x SIP Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

It is too early to determine the full implication of these decisions on environmental compliance strategy. However, independent obligations under the CAA, including obligations under future state implementation plan submittals, and actions taken pursuant to the recent settlement of the NSR enforcement action, are consistent with the actions included in a least-cost CAIR compliance plan. Consequently, management does not anticipate making any immediate changes in near-term compliance plans as a result of these court decisions.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. Management asserted claims against certain companies that sold power to KPCo and other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities.

5. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and six months ended June 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended June 30,		Three Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 23	$ 11	$ 11
Interest Cost	62	57	28	26
Expected Return on Plan Assets	(84)	(82)	(28)	(26)
Amortization of Transition Obligation	-	-	7	7
Amortization of Net Actuarial Loss	10	14	2	3
Net Periodic Benefit Cost	$ 13	$ 12	$ 20	$ 21

	Pension Plans		Other Postretirement Benefit Plans	
	Six Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 50	$ 47	$ 21	$ 21
Interest Cost	125	116	56	52
Expected Return on Plan Assets	(168)	(167)	(56)	(52)
Amortization of Transition Obligation	-	-	14	14
Amortization of Net Actuarial Loss	19	29	5	6
Net Periodic Benefit Cost	$ 26	$ 25	$ 40	$ 41

The following table provides KPCo's net periodic benefit cost for the plans for the three and six months ended June 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
	(in thousands)			
Three Months Ended June 30,	$ 249	$ 254	$ 400	$ 427
Six Months Ended June 30,	498	509	801	853

6. BUSINESS SEGMENTS

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

7. INCOME TAXES

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

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

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, KPCo and other AEP subsidiaries have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2003 and have issues that will be pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

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

State Tax Legislation

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

8. FINANCING ACTIVITIES

Lines of Credit

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of June 30, 2008 and December 31, 2007 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the six months ended June 30, 2008 are described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of June 30, 2008	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 51,504	$ -	$ 31,644	$ -	$ 48,435	$ 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, 2008 and 2007 are summarized in the following table:

	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates For Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2008	5.37%	2.91%	-%	-%	3.39%	-%
2007	5.46%	5.30%	-%	-%	5.36%	-%

Credit Facilities

In April 2008, the Parent, the AEP East companies and the AEP West companies entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement. Under the facilities, letters of credit may be issued. As of June 30, 2008, there were no outstanding amounts for KPCo under either facility.

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Kentucky Power Company

2008 Third Quarter Report

Financial Statements

AEP AMERICAN ELECTRIC POWER

TABLE OF CONTENTS	Page

GLOSSARY OF TERMS

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

Term	Meaning
AEP or Parent	American Electric Power Company, Inc.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
ALJ	Administrative Law Judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
CAA	Clean Air Act.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
FSP	FASB Staff Position.
FTR	Financial Transmission Right.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IRS	Internal Revenue Service.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
NO_x	Nitrogen Oxide.
NSR	New Source Review.
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.
PUCO	Public Utility Commission of Ohio.
PUCT	Public Utility Commission of Texas.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
RTO	Regional Transmission Organization.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.

Term	Meaning
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF INCOME
For the Three and Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Three Months Ended 2008	Three Months Ended 2007	Nine Months Ended 2008	Nine Months Ended 2007
REVENUES				
Electric Generation, Transmission and Distribution	$ 171,257	$ 133,712	$ 446,468	$ 397,478
Sales to AEP Affiliates	17,457	18,233	56,239	42,856
Other	158	255	506	492
TOTAL	188,872	152,200	503,213	440,826
EXPENSES				
Fuel and Other Consumables Used for Electric Generation	52,723	39,038	116,196	117,463
Purchased Electricity for Resale	10,034	5,752	19,506	12,514
Purchased Electricity from AEP Affiliates	63,469	47,587	177,921	134,422
Other Operation	20,524	18,730	49,909	49,248
Maintenance	10,389	9,643	36,912	28,190
Depreciation and Amortization	11,996	11,719	35,895	35,245
Taxes Other Than Income Taxes	2,967	2,916	7,019	8,692
TOTAL	172,102	135,385	443,358	385,774
OPERATING INCOME	16,770	16,815	59,855	55,052
Other Income (Expense):				
Interest Income	209	582	2,050	766
Allowance for Equity Funds Used During Construction	251	1	928	39
Interest Expense	(7,058)	(7,418)	(21,409)	(21,630)
INCOME BEFORE INCOME TAX EXPENSE	10,172	9,980	41,424	34,227
Income Tax Expense	2,721	3,495	11,899	11,301
NET INCOME	$ 7,451	$ 6,485	$ 29,525	$ 22,926

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

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2006	$ 50,450	$ 208,750	$ 108,899	$ 1,552	$ 369,651
FIN 48 Adoption, Net of Tax			(786)		(786)
Common Stock Dividends			(10,999)		(10,999)
TOTAL					357,866
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $943				(1,751)	(1,751)
NET INCOME			22,926		22,926
TOTAL COMPREHENSIVE INCOME					21,175
SEPTEMBER 30, 2007	$ 50,450	$ 208,750	$ 120,040	$ (199)	$ 379,041
DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
EITF 06-10 Adoption, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(7,500)		(7,500)
TOTAL					379,104
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $236				439	439
NET INCOME			29,525		29,525
TOTAL COMPREHENSIVE INCOME					29,964
SEPTEMBER 30, 2008	$ 50,450	$ 208,750	$ 150,243	$ (375)	$ 409,068

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
ASSETS
September 30, 2008 and December 31, 2007
(in thousands)
(Unaudited)

	2008	2007
CURRENT ASSETS		
Cash and Cash Equivalents	$ 455	$ 727
Accounts Receivable:		
Customers	27,828	20,196
Affiliated Companies	5,445	15,984
Accrued Unbilled Revenues	3,650	2,904
Miscellaneous	388	178
Allowance for Uncollectible Accounts	(5,384)	(1,071)
Total Accounts Receivable	31,927	38,191
Fuel	18,805	8,338
Materials and Supplies	10,491	11,758
Risk Management Assets	15,248	12,121
Regulatory Asset for Under-Recovered Fuel Costs	16,602	4,426
Prepayments and Other	6,677	4,024
TOTAL	100,205	79,585
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	491,200	482,653
Transmission	425,878	402,259
Distribution	520,250	502,486
Other	65,801	61,665
Construction Work in Progress	67,591	46,439
Total	1,570,720	1,495,502
Accumulated Depreciation and Amortization	473,868	457,028
TOTAL - NET	1,096,852	1,038,474
OTHER NONCURRENT ASSETS		
Regulatory Assets	129,512	124,828
Long-term Risk Management Assets	11,427	14,826
Deferred Charges and Other	47,676	53,708
TOTAL	188,615	193,362
TOTAL ASSETS	$ 1,385,672	$ 1,311,421

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
September 30, 2008 and December 31, 2007
(Unaudited)

	2008	2007
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 65,092	$ 19,153
Accounts Payable:		
General	47,511	32,603
Affiliated Companies	19,053	29,437
Long-term Debt Due Within One Year – Nonaffiliated	30,000	30,000
Risk Management Liabilities	13,917	10,310
Customer Deposits	15,717	14,422
Accrued Taxes	16,572	16,875
Other	22,338	31,909
TOTAL	230,200	184,709
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,512	398,373
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	6,831	9,699
Deferred Income Taxes	253,242	240,858
Regulatory Liabilities and Deferred Investment Tax Credits	43,443	46,434
Deferred Credits and Other	24,376	24,379
TOTAL	746,404	739,743
TOTAL LIABILITIES	976,604	924,452
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	150,243	128,583
Accumulated Other Comprehensive Income (Loss)	(375)	(814)
TOTAL	409,068	386,969
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,385,672	$ 1,311,421

See Condensed Notes to Condensed Financial Statements.

KENTUCKY POWER COMPANY
CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2008 and 2007
(in thousands)
(Unaudited)

	2008	2007
OPERATING ACTIVITIES		
Net Income	$ 29,525	$ 22,926
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:		
Depreciation and Amortization	35,895	35,245
Deferred Income Taxes	5,709	(893)
Allowance for Equity Funds Used During Construction	(928)	(39)
Mark-to-Market of Risk Management Contracts	1,494	720
Change in Other Noncurrent Assets	(987)	1,436
Change in Other Noncurrent Liabilities	(286)	3,205
Changes in Certain Components of Working Capital:		
Accounts Receivable, Net	6,264	7,150
Fuel, Materials and Supplies	(9,200)	3,754
Accounts Payable	7,051	(9,093)
Customer Deposits	1,295	1,332
Accrued Taxes, Net	510	(694)
Fuel Over/Under Recovery, Net	(12,176)	8,994
Other Current Assets	(3,466)	(2,129)
Other Current Liabilities	(7,927)	(1,326)
Net Cash Flows from Operating Activities	52,773	70,588
INVESTING ACTIVITIES		
Construction Expenditures	(91,457)	(43,917)
Change in Advances to Affiliates, Net	-	(181,329)
Proceeds from Sales of Assets	577	554
Net Cash Flows Used for Investing Activities	(90,880)	(224,692)
FINANCING ACTIVITIES		
Issuance of Long-term Debt – Nonaffiliated	-	321,141
Change in Advances from Affiliates, Net	45,939	(30,636)
Retirement of Long-term Debt – Affiliated	-	(125,000)
Principal Payments for Capital Lease Obligations	(604)	(665)
Dividends Paid on Common Stock	(7,500)	(10,999)
Net Cash Flows from Financing Activities	37,835	153,841
Net Decrease in Cash and Cash Equivalents	(272)	(263)
Cash and Cash Equivalents at Beginning of Period	727	702
Cash and Cash Equivalents at End of Period	$ 455	$ 439
SUPPLEMENTARY INFORMATION		
Cash Paid for Interest, Net of Capitalized Amounts	$ 24,376	$ 20,661
Net Cash Paid (Received) for Income Taxes	(231)	5,895
Noncash Acquisitions Under Capital Leases	237	645
Construction Expenditures Included in Accounts Payable at September 30,	9,634	2,428

See Condensed Notes to Condensed Financial Statements.

CONDENSED NOTES TO CONDENSED FINANCIAL STATEMENTS

1. Significant Accounting Matters
2. New Accounting Pronouncements
3. Rate Matters
4. Commitments, Guarantees and Contingencies
5. Benefit Plans
6. Business Segments
7. Income Taxes
8. Financing Activities

1. SIGNIFICANT ACCOUNTING MATTERS

General

The accompanying unaudited condensed financial statements and footnotes were prepared in accordance with GAAP for interim financial information. Accordingly, they do not include all of the information and footnotes required by GAAP for complete annual financial statements.

In the opinion of management, the unaudited condensed interim financial statements reflect all normal and recurring accruals and adjustments necessary for a fair presentation of the net income, financial position and cash flows for the interim periods. The net income for the three and nine months ended September 30, 2008 are not necessarily indicative of results that may be expected for the year ending December 31, 2008. The accompanying condensed financial statements are unaudited and should be read in conjunction with the audited 2007 financial statements and notes thereto, which are included in KPCo's 2007 Annual Report.

Reclassifications

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

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of new pronouncements issued or implemented in 2008 and standards issued but not implemented that management has determined relate to KPCo's operations.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period.

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

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

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

In October 2008, the FASB issued FSP SFAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on KPCo's financial statements.

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

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

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

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

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

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

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

The following table sets forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of September 30, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of September 30, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets:					
Risk Management Contracts (a)	$ 1,555	$ 106,224	$ 1,070	$ (86,135)	$ 22,714
Cash Flow and Fair Value Hedges (a)	-	1,976	-	(1,064)	912
Dedesignated Risk Management Contracts (b)	-	-	-	3,049	3,049
Total Risk Management Assets	$ 1,555	$ 108,200	$ 1,070	$ (84,150)	$ 26,675
Liabilities:					
Risk Management Liabilities:					
Risk Management Contracts (a)	$ 2,264	$ 98,922	$ 2,057	$ (84,487)	$ 18,756
Cash Flow and Fair Value Hedges (a)	-	1,705	-	(1,064)	641
DETM Assignment (c)	-	-	-	1,351	1,351
Total Risk Management Liabilities	$ 2,264	$ 100,627	$ 2,057	$ (84,200)	$ 20,748

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 13 in the 2007 Annual Report.

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:

	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of July 1, 2008	$ (3,970)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	956
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements	-
Transfers in and/or out of Level 3 (b)	1,196
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	831
Balance as of September 30, 2008	$ (987)

	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of January 1, 2008	$ (157)
Realized (Gain) Loss Included in Earnings (or Changes in Net Assets) (a)	79
Unrealized Gain (Loss) Included in Earnings (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements	-
Transfers in and/or out of Level 3 (b)	(146)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(763)
Balance as of September 30, 2008	$ (987)

(a) Included in revenues on KPCo's Condensed Statement of Income.

(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.

(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the Condensed Statements of Income. These net gains (losses) are recorded as regulatory assets/liabilities.

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

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

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

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

SFAS 160 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. The statement is applied prospectively upon adoption. Early adoption is prohibited. Upon adoption, prior period financial statements will be restated for the presentation of the noncontrolling interest for comparability. Management expects that the adoption of this standard will have an immaterial impact on the financial statements. KPCo will adopt SFAS 160 effective January 1, 2009.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how derivative instruments and related hedged items are accounted for under SFAS 133 and its related interpretations, and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. SFAS 161 requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation. This standard is intended to improve upon the existing disclosure framework in SFAS 133.

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

SFAS 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162)

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

SFAS 162 is effective 60 days after the SEC approves the Public Company Accounting Oversight Board's amendments to AU Section 411, "The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles." Management expects the adoption of this standard will have no impact on KPCo's financial statements. KPCo will adopt SFAS 162 when it becomes effective.

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

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement in accordance with SFAS 106 "Employers' Accounting for Postretirement Benefits Other Than Pension" or Accounting Principles Board Opinion No. 12 "Omnibus Opinion – 1967" if the employer has agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a change in accounting principle through a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) a change in accounting principle through retrospective application to all prior periods. KPCo adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $562 thousand ($365 thousand, net of tax) to beginning earnings.

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

In June 2007, the FASB ratified the EITF consensus on the treatment of income tax benefits of dividends on employee share-based compensation. The issue is how a company should recognize the income tax benefit received on dividends that are paid to employees holding equity-classified nonvested shares, equity-classified nonvested share units or equity-classified outstanding share options and charged to retained earnings under SFAS 123R, "Share-Based Payments." Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital. EITF 06-11 is applied prospectively to the income tax benefits of dividends on equity-classified employee share-based payment awards that are declared in fiscal years after December 15, 2007.

KPCo adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on the financial statements.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the EITF consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities.

EITF 08-5 is effective for the first reporting period beginning after December 15, 2008. It will be applied prospectively upon adoption with the effect of initial application included as a change in fair value of the liability in the period of adoption. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application. Early adoption is permitted. Although management has not completed an analysis, management expects that the adoption of this standard will have an immaterial impact on the financial statements. KPCo will adopt this standard effective January 1, 2009.

FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" (SFAS 133-1 and FIN 45-4)

In September 2008, the FASB issued SFAS 133-1 and FIN 45-4 as amendments to original statements SFAS 133 and FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

The standard is effective for interim and annual reporting periods ending after November 15, 2008. Upon adoption, the guidance will be prospectively applied. Management expects that the adoption of this standard will have an immaterial impact on the financial statements but increase the FIN 45 guarantees disclosure requirements. KPCo will adopt the standard effective December 31, 2008.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset under SFAS 142, "Goodwill and Other Intangible Assets." The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

SFAS 142-3 is effective for interim and annual periods in fiscal years beginning after December 15, 2008. Early adoption is prohibited. Upon adoption, the guidance within SFAS 142-3 will be prospectively applied to intangible assets acquired after the effective date. Management expects that the adoption of this standard will have an immaterial impact on the financial statements. KPCo will adopt SFAS 142-3 effective January 1, 2009.

FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FIN 39-1)

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

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

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

For certain risk management contracts, KPCo is required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the September 30, 2008 balance sheet, KPCo netted $1.8 million of cash collateral received from third parties against short-term and long-term risk management assets and $116 thousand of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, hedge accounting, trading inventory and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

3. <u>RATE MATTERS</u>

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

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that it has the authority to provide for surcharges and surcredits until the court of appeals rules. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time.

Management expects any adverse court of appeals decision could be applied prospectively, but it is possible that a retrospective refund could also be ordered. KPCo's exposure is indeterminable at this time although an adverse decision would have an unfavorable effect on future net income and cash flows, assuming the legislature does not enact legislation that authorizes such surcharges.

2008 Fuel Cost Reconciliation

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM's implementation of marginal loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo's semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM. For the nine months ended September 30, 2008, KPCo recorded $16 million of income and the related Regulatory Asset for Under-Recovered Fuel Costs for transmission line losses incurred from June 2007 through September 2008 of which $7 million related to 2007.

<u>FERC Rate Matters</u>

Regional Transmission Rate Proceedings at the FERC

<u>*SECA Revenue Subject to Refund*</u>

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC's direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers have engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

During 2006, based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $37 million and $5 million in 2006 and 2007, respectively, applicable to a total of $220 million of SECA revenues. KPCo provided reserves of $3 million and $400 thousand in 2006 and 2007, respectively.

AEP has completed settlements totaling $7 million applicable to $75 million of SECA revenues. The balance in the reserve for future settlements as of September 2008 was $35 million. In-process settlements total $3 million applicable to $37 million of SECA revenues. Management believes that the available $32 million of reserves for possible refunds are sufficient to settle the remaining $108 million of contested SECA revenues.

If the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $32 million is adequate to cover all remaining settlements. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if necessary.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP requested rehearing of this order, which the FERC denied. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005. I&M requested recovery of these lost revenues in its Indiana rate filing in January 2008 but does not expect to commence recovering the new rates until early 2009. Future net income and cash flows will continue to be adversely affected in Indiana and Michigan until the remaining 20% of the lost T&O transmission revenues are recovered in retail rates.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. Should this effort be successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in additional annual revenues of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies to be recovered in retail rates. Retail rates for jurisdictions other than Ohio are not affected until the next base rate filing at FERC. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. Management is unable to predict the outcome of this filing.

FERC Market Power Mitigation

The FERC allows utilities to sell wholesale power at market-based rates if they can demonstrate that they lack market power in the markets in which they participate. Sellers with market rate authority must, at least every three years, update their studies demonstrating lack of market power. In December 2007, AEP filed its most recent triennial update. In March and May 2008, the PUCO filed comments suggesting that the FERC should further investigate whether AEP continues to pass the FERC's indicative screens for the lack of market power in PJM. Certain industrial retail customers also requested the FERC to further investigate this matter. AEP responded that its market power studies were performed in accordance with the FERC's guidelines and continue to demonstrate lack of market power. In September 2008, the FERC issued an order accepting AEP's market-based rates with minor changes and rejected the PUCO's and the industrial retail customers' suggestions to further investigate AEP's lack of market power.

In an unrelated matter, in May 2008, the FERC issued an order in response to a complaint from the state of Maryland's Public Service Commission to hold a future hearing to review the structure of the three pivotal market power supplier tests in PJM. In September 2008, PJM filed a report on the results of the PJM stakeholder process concerning the three pivotal supplier market power tests which recommended the FERC not make major revisions to the test because the test is not unjust or unreasonable.

The FERC's order will become final if no requests for rehearing are filed. If a request for rehearing is filed and ultimately results in a further investigation by the FERC which limits AEP's ability to sell power at market-based rates in PJM, it would result in an adverse effect on future off-system sales margins and cash flows.

Allocation of Off-system Sales Margins

In 2004, intervenors and the OCC staff argued that AEP had inappropriately under-allocated off-system sales credits to PSO by $37 million for the period June 2000 to December 2004 under a FERC-approved allocation agreement. An ALJ assigned to hear intervenor claims found that the OCC lacked authority to examine whether AEP deviated from the FERC-approved allocation methodology for off-system sales margins and held that any such complaints should be addressed at the FERC. In October 2007, the OCC adopted the ALJ's recommendation and orally directed the OCC staff to explore filing a complaint at the FERC alleging the allocation of off-system sales margins to PSO is not in compliance with the FERC-approved methodology which could result in an adverse effect on future net income and cash flows for AEP Consolidated, the AEP East companies and the AEP West companies. In June 2008, the ALJ issued a final recommendation and incorporated the prior finding that the OCC lacked authority to review AEP's application of a FERC-approved methodology. In June 2008, the Oklahoma Industrial Energy Consumers appealed the ALJ recommendation to the OCC. In August 2008, the OCC heard the appeal and a decision is pending. In August 2008, the OCC filed a complaint at the FERC alleging that AEPSC inappropriately allocated off-system trading margins between the AEP East companies and the AEP West companies and did not properly allocate off-system trading margins within the AEP West companies. The PUCT, the APSC and the Oklahoma Industrial Energy Consumers have all intervened in this filing.

TCC, TNC and the PUCT have been involved in litigation in the federal courts concerning whether the PUCT has the right to order a reallocation of off-system sales margins thereby reducing recoverable fuel costs in the final fuel reconciliation in Texas under the restructuring legislation.

Management cannot predict the outcome of these proceedings. However, management believes its allocations were in accordance with the then-existing FERC-approved allocation agreements and additional off-system sales margins should not be retroactively reallocated. The results of these proceedings could have an adverse effect on future net income and cash flows for AEP Consolidated, the AEP East companies and the AEP West companies.

4. COMMITMENTS, GUARANTEES AND CONTINGENCIES

KPCo is subject to certain claims and legal actions arising in its ordinary course of business. In addition, business activities are subject to extensive governmental regulation related to public health and the environment. The ultimate outcome of such pending or potential litigation cannot be predicted. For current proceedings not specifically discussed below, management does not anticipate that the liabilities, if any, arising from such proceedings would have a material adverse effect on the financial statements. The Commitments, Guarantees and Contingencies note within the 2007 Annual Report should be read in conjunction with this report.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to September 30, 2008, KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

Master Operating Lease

KPCo leases certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $3 million as of September 30, 2008.

CONTINGENCIES

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of this lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the U.S. Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

Clean Air Act Interstate Rule

In 2005, the Federal EPA issued a final rule, the Clean Air Interstate Rule (CAIR), that required further reductions in SO_2 and NO_x emissions and assists states developing new state implementation plans to meet 1997 national ambient air quality standards (NAAQS). CAIR reduces regional emissions of SO_2 and NO_x (which can be transformed into particulate matter and ozone) from power plants in the Eastern U.S. (29 states and the District of Columbia). Reduction of both SO_2 and NO_x would be achieved through a cap-and-trade program. In July 2008, the D.C. Circuit Court of Appeals issued a decision that would vacate the CAIR and remand the rule to the Federal EPA. In September 2008, the Federal EPA and other parties petitioned for rehearing. Management is unable to predict the outcome of the rehearing petitions or how the Federal EPA will respond to the remand which could be stayed or appealed to the U.S. Supreme Court.

KPCo did not purchase any significant number of CAIR allowances. SO_2 and seasonal NO_x allowances allocated to the AEP System's facilities under the Acid Rain Program and the NO_x state implementation plan (SIP) Call will still be required to comply with existing CAA programs that were not affected by the court's decision.

It is too early to determine the full implication of these decisions on environmental compliance strategy. However, independent obligations under the CAA, including obligations under future state implementation plan submittals, and actions taken pursuant to the settlement of the NSR enforcement action, are consistent with the actions included in a least-cost CAIR compliance plan. Consequently, management does not anticipate making any immediate changes in near-term compliance plans as a result of these court decisions.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. Management is unable to predict the outcome of these proceedings or their impact on future net income and cash flows.. Management asserted claims against certain companies that sold power to KPCo and other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities.

5. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. In addition, KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

Components of Net Periodic Benefit Cost

The following tables provide the components of AEP's net periodic benefit cost for the plans for the three and nine months ended September 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	Three Months Ended September 30,		Three Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 25	$ 24	$ 10	$ 11
Interest Cost	62	59	28	26
Expected Return on Plan Assets	(84)	(85)	(27)	(26)
Amortization of Transition Obligation	-	-	7	6
Amortization of Net Actuarial Loss	10	15	3	3
Net Periodic Benefit Cost	$ 13	$ 13	$ 21	$ 20

	Pension Plans		Other Postretirement Benefit Plans	
	Nine Months Ended September 30,		Nine Months Ended September 30,	
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 75	$ 72	$ 31	$ 32
Interest Cost	187	176	84	78
Expected Return on Plan Assets	(252)	(254)	(83)	(78)
Amortization of Transition Obligation	-	-	21	20
Amortization of Net Actuarial Loss	29	44	8	9
Net Periodic Benefit Cost	$ 39	$ 38	$ 61	$ 61

The following table provides KPCo's net periodic benefit cost for the plans for the three and nine months ended September 30, 2008 and 2007:

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
	(in thousands)			
Three Months Ended September 30,	$ 249	$ 255	$ 417	$ 426
Nine Months Ended September 30,	747	764	1,218	1,279

AEP has significant investments in several trust funds to provide for future pension and OPEB payments. All of the trust funds' investments are well-diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts has declined due to the decreases in the equity and fixed income markets. Although the asset values are currently lower, this decline has not affected the funds' ability to make their required payments.

6. BUSINESS SEGMENTS

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

7. INCOME TAXES

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

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

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, KPCo and other AEP subsidiaries have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2003 and have issues that are being pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

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

Federal Tax Legislation

In October 2008, the Emergency Economic Stabilization Act of 2008 (the Act) was signed into law. The Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits and energy efficient commercial building deductions. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income, cash flows or financial condition.

State Tax Legislation

In March 2008, the Governor of West Virginia signed legislation providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management has evaluated the impact of the law change and the application of the law change will not materially impact KPCo's net income, cash flows or financial condition.

8. FINANCING ACTIVITIES

Lines of Credit

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of September 30, 2008 and December 31, 2007 are included in Advances from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limit for the nine months ended September 30, 2008 are described in the following table:

Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of September 30, 2008	Authorized Short-Term Borrowing Limit
		(in thousands)			
$ 70,213	$ -	$ 38,946	$ -	$ 65,092	$ 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, 2008 and 2007 are summarized in the following table:

	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates For Funds Loaned to the Utility Money Pool	Average Interest Rate for Funds Borrowed from the Utility Money Pool	Average Interest Rate for Funds Loaned to the Utility Money Pool
2008	5.37%	2.91%	-%	-%	3.24%	-%
2007	5.92%	5.30%	5.94%	5.71%	5.50%	5.84%

Credit Facilities

In April 2008, KPCo and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of September 30, 2008, there were no outstanding amounts for KPCo under either facility.

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2007 Annual Report

KPSC Case No. 2009-00459
Pursuant to 807 KAR5:001
Section 10 (6) (s)
2007 KPCO Annual Report

Financial Statements

AEP AMERICAN® ELECTRIC POWER

TABLE OF CONTENTS

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GLOSARY 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.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated domestic electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
ERCOT	Electric Reliability Council of Texas.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 47	FASB Interpretation No. 47, "Accounting for Conditional Asset Retirement Obligations."
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
GAAP	Accounting Principles Generally Accepted in the United States of America.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IRS	Internal Revenue Service.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.

Term	Meaning
MTM	Mark-to-Market.
MW	Megawatt.
NO_x	Nitrogen oxide.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCT	Public Utility Commission of Texas.
PUHCA	Public Utility Holding Company Act.
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.
SEC	United States Securities and Exchange Commission.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 143	Statement of Financial Accounting Standards No. 143, "Accounting for Asset Retirement Obligations."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SFAS 159	Statement of Financial Accounting Standards No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of
Kentucky Power Company:

We have audited the accompanying balance sheets of Kentucky Power Company (the "Company") as of December 31, 2007 and 2006, and the related statements of income, changes in common shareholder's equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2007. 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 generally accepted auditing standards as established by the Auditing Standards Board (United States) and in accordance with the auditing 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. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing 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 over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, 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 financial statements present fairly, in all material respects, the financial position of Kentucky Power Company as of December 31, 2007 and 2006, and the results of its operations and its cash flows for the years then ended in conformity with accounting principles generally accepted in the United States of America.

As discussed in Notes 2 and 7 to the financial statements, respectively, the Company adopted FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes", effective January 1, 2007, and FASB Statement No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," effective December 31, 2006.

Deloitte + Touche LLP

Columbus, Ohio
February 28, 2008

KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	2007	2006	2005
REVENUES			
Electric Generation, Transmission and Distribution	$ 526,754	$ 526,432	$ 458,858
Sales to AEP Affiliates	60,551	58,287	70,803
Other	695	1,148	1,682
TOTAL	588,000	585,867	531,343
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	147,912	152,335	142,672
Purchased Electricity for Resale	17,786	8,724	7,213
Purchased Electricity from AEP Affiliates	185,399	192,080	176,350
Other Operation	66,118	60,674	59,024
Maintenance	36,880	35,430	30,652
Depreciation and Amortization	47,193	46,387	45,110
Taxes Other Than Income Taxes	11,872	8,612	9,491
TOTAL	513,160	504,242	470,512
OPERATING INCOME	74,840	81,625	60,831
Other Income (Expense):			
Interest Income	1,992	656	880
Allowance for Equity Funds Used During Construction	260	241	305
Interest Expense	(28,635)	(28,832)	(29,071)
INCOME BEFORE INCOME TAXES	48,457	53,690	32,945
Income Tax Expense	15,987	18,655	12,136
NET INCOME	$ 32,470	$ 35,035	$ 20,809

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

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CHANGES IN COMMON SHAREHOLDER'S EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
DECEMBER 31, 2004	$ 50,450	$ 208,750	$ 70,555	$ (8,775)	$ 320,980
Common Stock Dividends			(2,500)		(2,500)
TOTAL					318,480
COMPREHENSIVE INCOME					
Other Comprehensive Income (Loss), Net of Taxes:					
Cash Flow Hedges, Net of Tax of $542				(1,007)	(1,007)
Minimum Pension Liability, Net of Tax of $5,147				9,559	9,559
NET INCOME			20,809		20,809
TOTAL COMPREHENSIVE INCOME					29,361
DECEMBER 31, 2005	50,450	208,750	88,864	(223)	347,841
Common Stock Dividends			(15,000)		(15,000)
TOTAL					332,841
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $940				1,746	1,746
Minimum Pension Liability, Net of Tax of $16				29	29
NET INCOME			35,035		35,035
TOTAL COMPREHENSIVE INCOME					36,810
DECEMBER 31, 2006	50,450	208,750	108,899	1,552	369,651
FIN 48 Adoption, Net of Tax			(786)		(786)
Common Stock Dividends			(12,000)		(12,000)
TOTAL					356,865
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $1,274				(2,366)	(2,366)
NET INCOME			32,470		32,470
TOTAL COMPREHENSIVE INCOME					30,104
DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2007 and 2006
(in thousands)

	2007	2006
CURRENT ASSETS		
Cash and Cash Equivalents	$ 727	$ 702
Accounts Receivable:		
Customers	20,196	30,112
Affiliated Companies	15,984	10,540
Accrued Unbilled Revenues	2,904	3,602
Miscellaneous	178	327
Allowance for Uncollectible Accounts	(1,071)	(227)
Total Accounts Receivable	38,191	44,354
Fuel	8,338	16,070
Materials and Supplies	11,758	8,726
Risk Management Assets	12,480	25,624
Regulatory Asset for Under-Recovered Fuel Costs	4,426	1,042
Prepayments and Other	4,701	5,327
TOTAL	80,621	101,845
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Production	482,653	478,955
Transmission	402,259	394,419
Distribution	502,486	481,083
Other	61,665	61,089
Construction Work in Progress	46,439	29,587
Total	1,495,502	1,445,133
Accumulated Depreciation and Amortization	457,028	442,778
TOTAL - NET	1,038,474	1,002,355
OTHER NONCURRENT ASSETS		
Regulatory Assets	124,828	136,139
Long-term Risk Management Assets	15,356	21,282
Deferred Charges and Other	53,708	48,944
TOTAL	193,892	206,365
TOTAL ASSETS	$ 1,312,987	$ 1,310,565

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2007 and 2006

	2007	2006
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ 19,153	$ 30,636
Accounts Payable:		
General	32,603	31,490
Affiliated Companies	29,437	23,658
Long-term Debt Due Within One Year – Nonaffiliated	30,000	322,048
Risk Management Liabilities	10,974	20,001
Customer Deposits	15,312	16,095
Accrued Taxes	16,875	18,775
Other	31,909	26,303
TOTAL	186,263	489,006
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	398,373	104,920
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	9,711	15,426
Deferred Income Taxes	240,858	242,133
Regulatory Liabilities and Deferred Investment Tax Credits	46,434	49,109
Deferred Credits and Other	24,379	20,320
TOTAL	739,755	451,908
TOTAL LIABILITIES	926,018	940,914
Commitments and Contingencies (Note 5)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – $50 Par Value Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	208,750	208,750
Retained Earnings	128,583	108,899
Accumulated Other Comprehensive Income (Loss)	(814)	1,552
TOTAL	386,969	369,651
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,312,987	$ 1,310,565

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2007, 2006 and 2005
(in thousands)

	2007	2006	2005
OPERATING ACTIVITIES			
Net Income	$ 32,470	$ 35,035	$ 20,809
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	47,193	46,387	45,110
Deferred Income Taxes	5,691	2,596	10,555
Allowance for Equity Funds Used During Construction	(260)	(241)	(305)
Mark-to-Market of Risk Management Contracts	2,479	580	(3,465)
Pension Contributions to Qualified Plan Trusts	-	-	(18,894)
Change in Other Noncurrent Assets	(4,122)	(4,497)	(114)
Change in Other Noncurrent Liabilities	1,001	2,621	3,844
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	2,445	11,903	(3,681)
Fuel, Materials and Supplies	9,015	(6,125)	(2,735)
Accounts Payable	1,806	(3,436)	13,184
Customer Deposits	(783)	(5,548)	9,334
Accrued Taxes, Net	(1,410)	15,547	(7,041)
Other Current Assets	(3,207)	7,867	(9,261)
Other Current Liabilities	1,376	3,953	1,589
Net Cash Flows from Operating Activities	93,694	106,642	58,929
INVESTING ACTIVITIES			
Construction Expenditures	(68,134)	(77,848)	(56,979)
Change in Other Cash Deposits, Net	-	5	(5)
Change in Advances to Affiliates, Net	-	-	16,127
Proceeds from Sales of Assets	695	2,956	300
Net Cash Flows Used for Investing Activities	(67,439)	(74,887)	(40,557)
FINANCING ACTIVITIES			
Issuance of Long-term Debt – Nonaffiliated	321,100	-	-
Change in Advances from Affiliates, Net	(11,483)	24,596	6,040
Retirement of Long-term Debt – Nonaffiliated	(322,964)	-	-
Retirement of Long-term Debt – Affiliated	-	(40,000)	(20,000)
Principal Payments for Capital Lease Obligations	(883)	(1,175)	(1,518)
Dividends Paid on Common Stock	(12,000)	(15,000)	(2,500)
Net Cash Flows Used for Financing Activities	(26,230)	(31,579)	(17,978)
Net Increase in Cash and Cash Equivalents	25	176	394
Cash and Cash Equivalents at Beginning of Period	702	526	132
Cash and Cash Equivalents at End of Period	$ 727	$ 702	$ 526
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 28,864	$ 27,887	$ 27,354
Net Cash Paid for Income Taxes	10,477	11,516	11,655
Noncash Acquisitions Under Capital Leases	826	648	419
Construction Expenditures Included in Accounts Payable at December 31,	12,161	3,357	6,553

See Notes to Financial Statements.

NOTES TO FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies
2. New Accounting Pronouncements
3. Rate Matters
4. Effects of Regulation
5. Commitments, Guarantees and Contingencies
6. Company-wide Staffing and Budget Review
7. Benefit Plans
8. Business Segments
9. Derivatives, Hedging and Financial Instruments
10. Income Taxes
11. Leases
12. Financing Activities
13. Related Party Transactions
14. Property, Plant and Equipment
15. Unaudited Quarterly Financial Information

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 176,000 retail customers in its service territory in eastern Kentucky. As a member of the AEP Power Pool, KPCo shares the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. KPCo also sells power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Under a unit power agreement with AEGCo, an affiliated company that is not a member of the AEP Power Pool, KPCo purchases 15% of the total output of the 2,600 MW Rockport Plant capacity. Therefore, KPCo purchases 390 MW 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.

Prior to April 1, 2006, under the SIA, AEPSC allocated physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities among AEP East companies and AEP West companies based on an allocation methodology established at the time of the AEP-CSW merger. Sharing in a calendar year was based upon the level of such activities experienced for the twelve months ended June 30, 2000, which immediately preceded the merger. This activity resulted in an AEP East companies' and AEP West companies' allocation of approximately 91% and 9%, respectively, for revenues and expenses. Allocation percentages in any given calendar year were also based upon the relative generating capacity of the AEP East companies and AEP West companies in the event the pre-merger activity level was exceeded. The capacity-based allocation mechanism was triggered in July 2005, resulting in an allocation factor of approximately 70% and 30% for the AEP East companies and AEP West companies, respectively, for the remainder of each year.

Effective April 1, 2006, under the SIA, AEPSC allocates physical and financial revenues and expenses from neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT 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. Accordingly, the 2006 results of operations and cash flows reflect nine months of the SIA change.

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

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

KPCo's affiliated transactions are regulated by the FERC under the 2005 Public Utility Holding Company Act (2005 PUHCA) and by the KPSC. The KPSC approves the retail rates KPCo charges and regulates KPCo's retail services and operations for the generation and supply of power, retail transmission and distribution energy delivery services.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission services. KPCo's wholesale power transactions are generally market-based and are not cost-based regulated unless KPCo negotiates and files a cost-based contract with the FERC or the FERC determines that KPCo has "market power" in the region in which the transaction is taking place. KPCo enters into wholesale power supply contracts with various municipalities and cooperatives that are FERC regulated, cost-based contracts.

In addition, the FERC regulates the AEP Power Pool, the Transmission Equalization Agreement, the System Interim Allowance Agreement, and SIA, all of which allocate shared AEP system costs and revenues to the utility subsidiaries that are parties to the agreements, including KPCo.

The KPSC regulates all of the retail public utility operations (generation/power supply, transmission and distribution operations) and retail rates of KPCo, which are cost-based. In 2005, KPCo was subject to regulation by the SEC under the Public Utility Holding Company Act of 1935 (1935 PUHCA). The Energy Policy Act of 2005 repealed the 1935 PUHCA effective February 8, 2006 and replaced it with the 2005 PUHCA. With the repeal of the 1935 PUHCA, the SEC no longer has jurisdiction over the activities of registered holding companies, their respective service corporations and their intercompany transactions, which it regulated since 1935 predominantly at cost. Jurisdiction over holding company-related activities was transferred to the FERC and the required reporting was reduced by the 2005 PUHCA. 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, mergers with another electric utility or holding company, inter-company transactions, accounting and AEPSC intercompany service billings which are generally at cost. The intercompany sale of non-power goods and non-AEPSC services to affiliates cannot exceed market under the 2005 PUHCA.

Both the FERC and the KPSC are permitted to review and audit the books and records of KPCo.

Accounting for the Effects of Cost-Based Regulation

As a cost-based 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 SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues.

Use of Estimates

The preparation of these financial statements in conformity with accounting principles generally accepted in the United States of America 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, 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.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for cost-based rate-regulated operations under the group composite method of 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. 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 depreciation rates that are established for the generating plants 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 SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets." 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 and investment is the amount at which that asset and 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 domestic regulated electric utility plant.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

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 or delivery 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, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable for KPCo. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishments of Liabilities," allowing the receivables to be removed from KPCo's balance sheet (see "Sale of Receivables - AEP Credit" section of Note 12).

Deferred Fuel Costs

The cost of fuel and related chemical and emission allowance consumables is charged to Fuel and Other Consumables Used for Electric Generation Expense when the fuel is burned or the consumable is utilized. Where applicable under governing state regulatory commission retail rate orders, fuel cost over-recoveries (the excess of fuel revenues billed to customers over fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, state regulatory commissions audit fuel cost calculations. When a fuel cost disallowance becomes probable, KPCo adjusts its deferrals and records provisions for estimated refunds to recognize the probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when the fuel clauses have been suspended or terminated.

In general, changes in fuel costs are reflected in rates in a timely manner through the fuel cost adjustment clause. A portion of profits from off-system sales are shared with customers through the fuel clause.

Revenue Recognition

Regulatory Accounting

The financial statements for cost-based rate-regulated operations 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 to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and/or financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on the balance sheet. KPCo tests for probability of recovery whenever new events occur, for example, 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 earnings.

Traditional Electricity Supply and Delivery Activities

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

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory, and the AEP East companies purchase power back from the same RTO to supply power to KPCo's load. These power sales and purchases are reported on a net basis in Revenues in the Statements of Income.

Physical energy purchases, including those from all RTOs that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph, are accounted for on a gross basis in Purchased Electricity for Resale in the Statements of Income.

KPCo records expenses upon receipt of purchased electricity and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting. KPCo, which operates solely in a jurisdiction where the generation /supply business is subject to cost-based regulation, defers the unrealized MTM amounts as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

KPCo engages in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets. KPCo's activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. KPCo engages in certain energy marketing and risk management transactions 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 as a normal purchase or sale. The realized gains and losses on wholesale marketing and risk management transactions are included in Revenues in 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 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 Accumulated Other Comprehensive Income (Loss). When the forecasted transaction is realized and affects earnings, KPCo subsequently reclassifies the gain or loss on the hedge from Accumulated Other Comprehensive Income into revenues or expenses on its Statements of Income, within the same financial statement line item as the forecasted transaction. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains).

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 its 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 FIN 48. Effective with the adoption of FIN 48, KPCo classifies interest expense or income related to uncertain tax positions as interest expense or income as appropriate and classifies penalties as Other Operation.

Excise Taxes

KPCo, as an agent for some state and local governments, collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not record 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 associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting 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.

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 all 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 Other Noncurrent Assets-Deferred Charges and Other. 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. Allowances held for speculation are included in Current Assets-Prepayments and Other. 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 costs and the amortization of regulatory assets.

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).

Components of Accumulated Other Comprehensive Income (Loss) (AOCI)

AOCI is included on the balance sheets in the common shareholder's equity section. AOCI for KPCo as of December 31, 2007 and 2006 is shown in the following table.

	December 31,	
	2007	2006
Components	(in thousands)	
Cash Flow Hedges	$ (814)	$ 1,552

Earnings Per Share (EPS)

KPCo is a wholly-owned subsidiary of AEP. Therefore, KPCo is not required to report EPS.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. These revisions had no impact on KPCo's previously reported results of operations or changes in shareholder's equity.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of exposure drafts or final pronouncements, management thoroughly reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of final pronouncements that management has determined relate to KPCo's operations.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It establishes how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. SFAS 141R requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period.

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

SFAS 157 "Fair Value Measurements" (SFAS 157)

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

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

In February 2008, the FASB issued FSP FAS 157-2 "Effective Date of FASB Statement No. 157" which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually).

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

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

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

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

SFAS 160 "Noncontrolling Interest in Consolidated Financial Statements" (SFAS 160)

In December 2007, the FASB issued SFAS 160, modifying reporting for noncontrolling interest (minority interest) in consolidated financial statements. It requires noncontrolling interest be reported in equity and establishes a new framework for recognizing net income or loss and comprehensive income by the controlling interest. Upon deconsolidation due to loss of control over a subsidiary, the standard requires a fair value remeasurement of any remaining noncontrolling equity investment to be used to properly recognize the gain or loss. SFAS 160 requires specific disclosures regarding changes in equity interest of both the controlling and noncontrolling parties and presentation of the noncontrolling equity balance and income or loss for all periods presented.

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

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

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

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

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

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

FIN 48 "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of Settlement in FASB Interpretation No. 48" (FIN 48)

In July 2006, the FASB issued FASB Interpretation No. 48 "Accounting for Uncertainty in Income Taxes" and in May 2007, the FASB issued FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48." FIN 48 clarifies the accounting for uncertainty in income taxes recognized in an enterprise's financial statements by prescribing a recognition threshold (whether a tax position is more likely than not to be sustained) without which, the benefit of that position is not recognized in the financial statements. It requires a measurement determination for recognized tax positions based on the largest amount of benefit that is greater than 50 percent likely of being realized upon ultimate settlement. FIN 48 also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition.

FIN 48 requires that the cumulative effect of applying this interpretation be reported and disclosed as an adjustment to the opening balance of retained earnings for that fiscal year and presented separately. KPCo adopted FIN 48 effective January 1, 2007. The impact of this interpretation was an unfavorable adjustment to retained earnings of $786 thousand.

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

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

KPCo adopted FIN 39-1 effective January 1, 2008. This standard changed the method of netting certain balance sheet amounts and reduced assets and liabilities by an immaterial amount. It requires retrospective application as a change in accounting principle for all periods presented.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued by the FASB, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, liabilities and equity, derivatives disclosures, emission allowances, leases, insurance, subsequent events and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future results of operations and financial position.

3. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and their state commission. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on the results of operations and cash flows.

Kentucky Rate Matters

Validity of Nonstatutory Surcharges

In August 2007, the Franklin Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. The KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable to KPCo, it is possible that the AG or another intervenor could challenge KPCo's existing surcharges, which are also not specifically authorized by statute. These include KPCo's fuel clause surcharge, annual Rockport Plant capacity surcharge, merger surcredit and off-system sales credit rider. These surcharges are currently producing net annual revenues of approximately $10 million. The KPSC has asked interested parties to brief the issue in KPCo's outstanding fuel cost proceeding. The AG has stated that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC has issued an order stating that it has the authority to provide for surcharges and surcredits until the Court of Appeals rules. The appeals process could take up to two years to complete. The AG agreed to stay its challenge during that time. KPCo's exposure is indeterminable at this time since it is not known whether a final adverse appeal could result in a refund of prior amounts collected, which could have an adverse effect on future results of operations and cash flows.

FERC Rate Matters

Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving AEP and ultimately its internal load customers to make up the short fall in revenues. Approximately $10 million of SECA revenues billed by PJM and recognized by the AEP East companies were not collected. The AEP East companies filed a motion with the FERC to force payment of these uncollected SECA billings. KPCo's portion of recognized gross SECA revenues is $17 million.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates was not recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount. As a result, SECA ratepayers are engaged with AEP in settlement discussions. Management has been advised by external FERC counsel that it is probable that the FERC will reverse the ALJ's decision as it is contrary to two prior FERC decisions and lacks merit.

In 2006, the AEP East companies provided reserves of $37 million for net refunds for current and future SECA settlements. After reviewing existing settlements, the AEP East companies increased their reserves by an additional $5 million in December 2007. KPCo provided reserves of $0.4 million and $3.0 million in 2007 and 2006, respectively. The AEP East companies have reached settlements related to approximately $69 million of the $220 million of SECA revenues for a net refund of $3 million. The AEP East companies are also in the process of completing two settlements-in-principle on an additional $36 million of SECA revenues and expect to make net refunds of $4 million when those settlements are approved. Thus, completed and in-process settlements cover $105 million of SECA revenues and cover about $7 million of the reserve for refund, leaving approximately $115 million of contested SECA revenues and $35 million of refund reserves. However, if the ALJ's initial decision was upheld in its entirety, it could result in a disallowance of approximately $90 million of the AEP East companies' remaining $115 million of unsettled gross SECA revenues. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the remaining reserve of $35 million is adequate to cover all remaining settlements and any uncollectible amounts. KPCo's portion of the reserve is $3 million.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. As directed by the FERC, management is working to settle the remaining $115 million of unsettled revenues within the remaining reserve balance. Although management believes it has meritorious arguments and can settle with the remaining customers within the amount provided, management cannot predict the ultimate outcome of ongoing settlement talks and, if necessary, any future FERC proceedings or court appeals. If the FERC adopts the ALJ's decision and/or AEP cannot settle a significant portion of the remaining unsettled claims within the amount provided, it will have an adverse effect on future results of operations and cash flows.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates and the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM will be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them. AEP had requested rehearing of this order which the FERC denied. Management expects to file an appeal. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, results of operations and cash flows.

The AEP East companies increased their retail rates in Ohio, Virginia, West Virginia and Kentucky to recover lost T&O and SECA revenues. The AEP East companies are presently recovering from retail customers, approximately 85% of the lost T&O/SECA transmission revenues of $128 million a year.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, voted to continue zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argues the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. Management expects to file for rehearing. Should this effort be successful, KPCo would reduce future retail rates in fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Marginal-Loss Pricing

In June 2007, in response to a 2006 FERC order, PJM revised its methodology for considering transmission line losses in generation dispatch and the calculation of locational marginal prices. Marginal-loss dispatch recognizes the varying delivery costs of transmitting electricity from individual generator locations to the places where customers consume the energy. Prior to the implementation of marginal-loss dispatch, PJM used average losses in dispatch and in the calculation of locational marginal prices. Locational marginal prices in PJM now include the real-time impact of transmission losses from individual sources to loads.

Due to the implementation of marginal-loss pricing, for the period June 1, 2007 through December 31, 2007, AEP experienced an increase in the cost of delivering energy from its generating plants to customer load zones, which was partially offset by cost recoveries. Management believes these additional costs should be recoverable through retail and/or cost-based wholesale rates and plans to seek recovery. KPCo's incremental PJM billings for the period June through December 2007 were $7 million. In the interim, the incremental PJM billings will continue to have an adverse effect on results of operations and cash flows. Management is unable to predict whether recovery will ultimately be approved.

AEP has initiated discussions with PJM regarding the impact it is experiencing from the change in methodology and will pursue a modification of such methodology through the appropriate PJM stakeholder processes.

Allocation of Off-system Sales Margins

In August 2007, the OCC issued an order adopting the ALJ's recommendation that the allocation of system sales/trading margins is a FERC jurisdictional issue. In October 2007, the OCC orally directed the OCC staff to explore filing a complaint at FERC alleging the allocation of off-system sales margins to PSO is improper.

In December 2007, some cities served by TNC requested the PUCT to initiate, or order TNC to initiate a proceeding at the FERC to determine if TNC misapplied its tariff. In January 2008, TNC filed a response with the PUCT recommending the cities' request be denied.

To date, no claim has been asserted at the FERC. Although management cannot predict if a complaint will be filed at the FERC, management believes the allocations were in accordance with the then-existing FERC-approved allocation agreement and additional off-system sales margins should not be retroactively reallocated to the AEP West companies. A reallocation of off-system sales margins from the AEP East companies to the AEP West companies could result in an adverse effect on future results of operations and cash flows for KPCo.

4. EFFECTS OF REGULATION

Regulatory Assets and Liabilities

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2007	December 31, 2006	Notes
Regulatory Assets:	(in thousands)		
Total Current Regulatory Assets –			
Under-recovered Fuel Costs (g)	$ 4,426	$ 1,042	(a) (f)
SFAS 109 Regulatory Asset, Net	$ 101,340	$ 100,439	(a) (d)
SFAS 158 Regulatory Asset (Note 7)	13,573	24,375	(a) (d)
Other	9,915	11,325	(b) (d)
Total Noncurrent Regulatory Assets	$ 124,828	$ 136,139	
Regulatory Liabilities:			
Asset Removal Costs	$ 33,106	$ 31,165	(c)
Deferred Investment Tax Credits	3,395	4,356	(a) (e)
Other	9,933	13,588	(a) (d)
Total Noncurrent Regulatory Liabilities	$ 46,434	$ 49,109	

(a) Amount does not earn a return.
(b) Includes items both earning and not earning a return.
(c) The liability for removal costs, which reduces rate base and the resultant return, will be discharged as removal costs are incurred.
(d) Recovery/refund period – various periods.
(e) Recovery/refund period – up to 12 years.
(f) Recovery/refund period – 1 year.
(g) Current Regulatory Asset – Under-recovered Fuel Costs are recorded in Prepayments and Other on KPCo's Balance Sheets.

Merger with CSW

On June 15, 2000, AEP merged with CSW so that CSW became a wholly-owned subsidiary of AEP. The key provision of the merger rate agreement was a rate reduction starting the third quarter 2000 through 2007 of $3.5 million per year in Kentucky. Rates will remain in effect until KPCo changes base rates. KPCo will file for new base rates in Kentucky when appropriate.

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 adverse effect on the financial statements.

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. The insurance includes coverage for 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. KPCo's 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 a South Carolina domiciled protected-cell captive insurance company together with and/or in addition to various industry mutual and 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 have a material adverse effect on results of operations, cash flows and financial condition.

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. Aggregate construction expenditures for 2008 through 2010 are estimated at approximately $360.4 million. The amounts for 2008, 2009 and 2010 are $126.8 million, $104.6 million and $129 million, respectively. 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.

KPCo enters into long-term contracts to acquire fuel for electric generation and transport it to its facilities. The longest contract extends to the year 2013. The contracts provide for periodic price adjustments and contain various clauses that would release KPCo from its obligations under certain conditions.

KPCo purchases 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. KPCo does not expect to incur penalty payments under these provisions that would materially affect results of operations, cash flows or financial condition.

GUARANTEES

There are certain immaterial liabilities recorded for guarantees in accordance with FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

<u>Contracts</u>

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. Prior to December 31, 2007 KPCo entered into sale agreements including indemnifications with a maximum exposure that was not significant. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to power purchase and sale activity conducted pursuant to the SIA.

<u>Master Operating Lease</u>

KPCo leases certain equipment under a master operating lease. Under the lease agreement, the lessor is guaranteed to receive up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo has committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance. Assuming the fair market value of the equipment is zero at the end of the lease term, the maximum potential loss for these lease agreements was approximately $2 million as of December 31, 2007.

CONTINGENCIES

Environmental Settlement

In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging that certain of KPCo's affiliates including APCo, CSPCo, I&M and OPCo modified units at certain of their coal-fired generating plants in violation of the New Source Review (NSR) requirements of the CAA. The alleged modifications occurred at the AEP System's generating units over a 20-year period.

As part of a global consent decree covering all coal-fired units in the five eastern states of the AEP System to resolve all past NSR allegations and secure a covenant not to sue for future claims from the Federal EPA, KPCo agreed to complete previously announced flue gas desulfurization emissions control equipment (scrubbers) on Unit 2 of the Big Sandy Plant by December 2015. The obligation to pay a $15 million civil penalty and provide $36 million for environmental mitigation projects coordinated with the federal government and $24 million to the states for environmental mitigation was shared by members of the AEP Power Pool. Under the consent decree, KPCo recorded its share of the costs of $5.2 million in Other Operation during the third quarter of 2007.

Management believes KPCo can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through regulated rates or market prices of electricity. If KPCo is unable to recover such costs, it would adversely affect KPCo's future results of operations, cash flows and possibly financial condition.

Carbon Dioxide (CO_2) Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The defendants' motion to dismiss the lawsuits was granted in September 2005. The dismissal was appealed to the Second Circuit Court of Appeals. Briefing and oral argument have concluded. On April 2, 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case. Management believes the actions are without merit and intends to defend against the claims.

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 (PCBs) and other hazardous and nonhazardous materials. KPCo currently incurs costs to safely dispose of these substances.

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. At December 31, 2007, 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 results of operations.

KPCo evaluates the potential liability for each Superfund site separately, but several general statements can be made regarding potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was 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.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and certain other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed and the U.S. Supreme Court decided that it will review the Ninth Circuit's decision in 2008. Management is unable to predict the outcome of these proceedings or their impact on future results of operations and cash flows. Management asserted claims against certain companies that sold power to KPCo and certain other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities.

6. COMPANY-WIDE STAFFING AND BUDGET REVIEW

KPCo recorded $1.1 million of severance benefits expense in 2005 (primarily in Other Operation and Maintenance) resulting from a company-wide staffing and budget review, including the allocation of approximately $19.2 million of severance benefits expense associated with AEPSC employees. Payments and accrual adjustments recorded during 2006 were immaterial and were settled by June 30, 2006.

7. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans and nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. KPCo participates in other postretirement benefit plans sponsored by AEP to provide medical and death benefits for retired employees.

KPCo adopted SFAS 158 as of December 31, 2006. It requires employers to fully recognize the obligations associated with defined benefit pension plans and OPEB plans, which include retiree healthcare, in their balance sheets. Previous standards required an employer to disclose the complete funded status of its plan only in the notes to the financial statements and provided that an employer delay recognition of certain changes in plan assets and obligations that affected the costs of providing benefits resulting in an asset or liability that often differed from the plan's funded status. SFAS 158 requires a defined benefit pension or postretirement plan sponsor to (a) recognize in its statement of financial position an asset for a plan's overfunded status or a liability for the plan's underfunded status, (b) measure the plan's assets and obligations that determine its funded status as of the end of the employer's fiscal year and (c) recognize, as a component of other comprehensive income, the changes in the funded status of the plan that arise during the year but are not recognized as a component of net periodic benefit cost pursuant to previous standards. It also requires an employer to disclose additional information on how delayed recognition of certain changes in the funded status of a defined benefit pension or OPEB plan affects net periodic benefit costs for the next fiscal year. KPCo recorded a SFAS 71 regulatory asset of $24.4 million for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes will be deferred for future recovery. The effect of this standard on the 2006 financial statements was a pretax AOCI adjustment that was fully offset by a SFAS 71 regulatory asset.

SFAS 158 requires adjustment of pretax AOCI at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount 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 and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating investment returns and discount rates.

The following tables provide a reconciliation of the changes in projected benefit obligations and fair value of assets for AEP's plans over the two-year period ending at the plan's measurement date of December 31, 2007, and their funded status as of December 31 for each year:

Projected Pension Obligations, Plan Assets, Funded Status as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
		(in millions)		
Change in Projected Benefit Obligation				
Projected Obligation at January 1	$ 4,108	$ 4,347	$ 1,818	$ 1,831
Service Cost	96	97	42	39
Interest Cost	235	231	104	102
Actuarial Gain	(64)	(293)	(91)	(55)
Plan Amendments	18	2	-	-
Benefit Payments	(284)	(276)	(130)	(112)
Participant Contributions	-	-	22	21
Medicare Subsidy	-	-	8	(8)
Projected Obligation at December 31	$ 4,109	$ 4,108	$ 1,773	$ 1,818
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,346	$ 4,143	$ 1,302	$ 1,172
Actual Return on Plan Assets	435	470	115	127
Company Contributions	7	9	91	94
Participant Contributions	-	-	22	21
Benefit Payments	(284)	(276)	(130)	(112)
Fair Value of Plan Assets at December 31	$ 4,504	$ 4,346	$ 1,400	$ 1,302
Funded (Underfunded) Status at December 31	$ 395	$ 238	$ (373)	$ (516)

Amounts Recognized on AEP's Balance Sheets as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ 482	$ 320	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(8)	(8)	(4)	(5)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(79)	(74)	(369)	(511)
Funded (Underfunded) Status	$ 395	$ 238	$ (373)	$ (516)

SFAS 158 Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2007 and 2006

	Pension Plans		Other Postretirement Benefit Plans	
	2007	2006	2007	2006
Components	(in millions)			
Net Actuarial Loss	$ 534	$ 759	$ 231	$ 354
Prior Service Cost (Credit)	14	(5)	4	4
Transition Obligation	-	-	97	124
Pretax AOCI	$ 548	$ 754	$ 332	$ 482
Recorded as				
Regulatory Assets	$ 453	$ 582	$ 204	$ 293
Deferred Income Taxes	33	60	45	66
Net of Tax AOCI	62	112	83	123
Pretax AOCI	$ 548	$ 754	$ 332	$ 482

Components of the Change in AEP's Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the year ended December 31, 2007 are as follows:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
2007 Actuarial Gain	$ (166)	$ (111)
Amortization of Actuarial Loss	(59)	(12)
2007 Prior Service Cost	19	-
Amortization of Transition Obligation	-	(27)
Total 2007 Pretax AOCI Change	$ (206)	$ (150)

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2007 and 2006, and the target allocation for 2008, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
Asset Category	2008	2007	2006
Equity Securities	55%	57%	63%
Real Estate	5%	6%	6%
Debt Securities	39%	36%	26%
Cash and Cash Equivalents	1%	1%	5%
Total	100%	100%	100%

The asset allocations for AEP's other postretirement benefit plans at the end of 2007 and 2006, and target allocation for 2008, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2008	2007	2006
Asset Category			
Equity Securities	66%	62%	66%
Debt Securities	33%	35%	32%
Cash and Cash Equivalents	1%	3%	2%
Total	100%	100%	100%

AEP's investment strategy for the employee benefit 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 plans' assets relative to the plans' liabilities. To minimize investment risk, AEP's employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to AEP's targeted allocation when considered appropriate. AEP's 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 investment policies prohibit investment in AEP securities, with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies.

The value of the pension plans' assets increased to $4.5 billion at December 31, 2007 from $4.3 billion at December 31, 2006. The qualified plans paid $277 million in benefits to plan participants during 2007 (nonqualified plans paid $7 million in benefits). The value of AEP's Postretirement Plans' assets increased to $1.4 billion in December 31, 2007 from $1.3 billion at December 31, 2006. The Postretirement Plans paid $130 million in benefits to plan participants during 2007.

AEP bases the 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.

	December 31,	
	2007	2006
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 3,914	$ 3,861
Nonqualified Pension Plans	77	78
Total	$ 3,991	$ 3,939

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 at December 31, 2007 and 2006 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2007	2006
	(in millions)	
Projected Benefit Obligation	$ 81	$ 82
Accumulated Benefit Obligation	$ 77	$ 78
Fair Value of Plan Assets	-	-
Accumulated Benefit Obligation Exceeds the Fair Value of Plan Assets	$ 77	$ 78

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31, used in the measurement of AEP's benefit obligations are shown in the following tables:

Assumptions	Pension Plans 2007	Pension Plans 2006	Other Postretirement Benefit Plans 2007	Other Postretirement Benefit Plans 2006
Discount Rate	6.00%	5.75%	6.20%	5.85%
Rate of Compensation Increase	5.90%(a)	5.90%(a)	N/A	N/A

(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.

N/A = Not Applicable

To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2007, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2008 expected cash flows for the pension (qualified and nonqualified) and other postretirement benefit plans is as follows:

Employer Contributions	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Required Contributions (a)	$ 8	$ 4
Additional Discretionary Contributions	-	73

(a) Contribution required to meet minimum funding requirement per the U.S. Department of Labor plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by the U.S. Department of Labor and the amount to pay unfunded nonqualified benefits. The contribution to the other postretirement benefit plans is generally based on the amount of the other postretirement benefit plans' periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of AEP's Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from the employer's assets, including both the employer's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. 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 AEP's pension benefits and other postretirement benefits are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2008	$ 356	$ 111	$ (10)
2009	362	121	(11)
2010	363	131	(11)
2011	363	141	(12)
2012	368	149	(13)
Years 2013 to 2017, in Total	1,861	864	(82)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for fiscal years 2007, 2006 and 2005:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2007	2006	2005	2007	2006	2005
			(in millions)			
Service Cost	$ 96	$ 97	$ 93	$ 42	$ 39	$ 42
Interest Cost	235	231	228	104	102	107
Expected Return on Plan Assets	(340)	(335)	(314)	(104)	(94)	(92)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost (Credit)	-	(1)	(1)	-	-	-
Amortization of Net Actuarial Loss	59	79	55	12	22	25
Net Periodic Benefit Cost	50	71	61	81	96	109
Capitalized Portion	(14)	(21)	(17)	(25)	(27)	(33)
Net Periodic Benefit Cost Recognized as Expense	$ 36	$ 50	$ 44	$ 56	$ 69	$ 76

Estimated amounts expected to be amortized to net periodic benefit costs from AEP's pretax accumulated other comprehensive income during 2008 are shown in the following table:

	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 26	$ 5
Prior Service Cost	1	1
Transition Obligation	-	27
Total Estimated 2008 Pretax AOCI Amortization	$ 27	$ 33

The following table provides KPCo's net periodic benefit cost for the plans for the years ended December 31, 2007, 2006 and 2005:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2007	2006	2005	2007	2006	2005
			(in thousands)			
Benefit Costs	$ 1,018	$ 1,435	$ 1,506	$ 1,706	$ 2,050	$ 2,204

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	Pension Plans			Other Postretirement Benefit Plans		
	2007	2006	2005	2007	2006	2005
Discount Rate	5.75%	5.50%	5.50%	5.85%	5.65%	5.80%
Expected Return on Plan Assets	8.50%	8.50%	8.75%	8.00%	8.00%	8.37%
Rate of Compensation Increase	5.90%	5.90%	3.70%	N/A	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2007 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, used for other postretirement benefit plans measurement purposes are shown below:

Health Care Trend Rates	2007	2006
Initial	7.5 %	8.0 %
Ultimate	5.0 %	5.0 %
Year Ultimate Reached	2012	2009

Assumed health care cost trend rates have a significant effect on the amounts reported for the other postretirement benefit 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	$ 19	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	185	(154)

AEP Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plans for substantially all employees. These plans offer participants an opportunity to contribute a portion of their pay, include features under Section 401(k) of the Internal Revenue Code and provide for company matching contributions. The matching contributions to the plan are 75% of the first 6% of eligible compensation contributed by the employee. The cost for contributions to these plans totaled $1.4 million in 2007, $1.3 million in 2006 and $1.2 million in 2005.

8. BUSINESS SEGMENTS

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

9. DERIVATIVES, HEDGING AND FINANCIAL INSTRUMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position 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 and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the influence that imperfections in marketplace transparency may cause pricing to be less than or more than what the price should be based purely on supply and demand. Because energy markets are imperfect and volatile, there are inherent risks related to the underlying assumptions in models used to fair value open long-term risk management contracts. Unforeseen events can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future results of operations and cash flows if market prices are not consistent with the approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in 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, KPCo designates a hedging instrument as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), KPCo recognizes the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in earnings. 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) until the period the hedged item affects earnings. KPCo recognizes any hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

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. Realized gains and losses on derivative instruments held for trading purposes are included in Revenues on a net basis in KPCo's Statements of Income. 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. Unrealized MTM gains and losses are recorded as regulatory assets (for losses) and regulatory liabilities (for gains).

Fair Value Hedging Strategies

At certain times, KPCo enters into interest rate derivative transactions in order to manage interest rate risk exposure. These interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. KPCo records gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Expense on the statements of income. During 2007, 2006 and 2005, KPCo recognized no hedge ineffectiveness related to these derivative transactions.

Cash Flow Hedging Strategies

KPCo enters into, and designates as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. At various times during 2007, 2006 and 2005, KPCo designated cash flow hedge relationships using these commodities. Management closely monitors the potential impacts of commodity price changes, and where appropriate, enters into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Revenues or fuel expense, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to energy commodities. During 2007, 2006 and 2005, KPCo recognized immaterial amounts related to hedge ineffectiveness. However, there was no earnings impact because KPCo operates in a regulated jurisdiction.

KPCo enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo enters into various derivative instruments to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. At various times during 2007, 2006 and 2005, KPCo designated interest rate derivatives as cash flow hedges. KPCo reclassifies gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which the interest payments being hedged occur. During 2007, 2006 and 2005, KPCo recognized immaterial amounts related to hedge ineffectiveness. However, there was no earnings impact because KPCo operates in a regulated jurisdiction.

The following table represents the activity in Accumulated Other Comprehensive Income (Loss) for derivative contracts that qualify as cash flow hedges for the years 2005, 2006 and 2007:

		(in thousands)
Balance at December 31, 2004	$	813
Effective portion of changes in fair value		81
Reclasses from AOCI to Net Income		(1,088)
Balance at December 31, 2005		(194)
Effective portion of changes in fair value		1,496
Impact Due to Changes in SIA		(106)
Reclasses from AOCI to Net Income		356
Balance at December 31, 2006		1,552
Effective portion of changes in fair value		(1,061)
Reclasses from AOCI to Net Income		(1,305)
Balance at December 31, 2007	$	(814)

The following table approximates net loss (gain) from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2007 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. In addition, the following table summarizes the maximum length of time that the variability of future cash flows is being hedged. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes.

Company	Portion Expected to be Reclassified to Earnings During the Next Twelve Months (in thousands)	Maximum Term for Exposure to Variability of Future Cash Flow (in months)
KPCo	$ (302)	$ 17

FINANCIAL INSTRUMENTS

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current interest rates offered for instruments with similar maturities. 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 significant financial instruments for KPCo at December 31, 2007 and 2006 are summarized in the following table.

	December 31,			
	2007		2006	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 448,373	$ 442,090	$ 446,968	$ 440,839

10. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31,		
	2007	2006	2005
	(in thousands)		
Income Tax Expense (Credit):			
Current	$ 11,258	$ 17,203	$ 2,803
Deferred	5,691	2,596	10,555
Deferred Investment Tax Credits	(962)	(1,144)	(1,222)
Total Income Tax	$ 15,987	$ 18,655	$ 12,136

Shown below is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	Years Ended December 31,		
	2007	2006	2005
	(in thousands)		
Net Income	$ 32,470	$ 35,035	$ 20,809
Income Taxes	15,987	18,655	12,136
Pretax Income	$ 48,457	$ 53,690	$ 32,945
Income Tax on Pretax Income at Statutory Rate (35%)	$ 16,960	$ 18,791	$ 11,531
Increase (Decrease) in Income Tax resulting from the following items:			
Depreciation	1,223	1,669	1,644
Allowance for Funds Used During Construction	(661)	(606)	(614)
Removal Costs	(1,766)	(1,361)	(995)
Investment Tax Credits, Net	(962)	(1,144)	(1,222)
State and Local Income Taxes	736	1,070	778
Other	457	236	1,014
Total Income Taxes	$ 15,987	$ 18,655	$ 12,136
Effective Income Tax Rate	33.0%	34.7%	36.8%

The following table shows the elements of the net deferred tax liability and the significant temporary differences:

	December 31, 2007	December 31, 2006
	(in thousands)	
Deferred Tax Assets	$ 35,037	$ 38,454
Deferred Tax Liabilities	(280,667)	(280,587)
Net Deferred Tax Liabilities	$ (245,630)	$ (242,133)
Property Related Temporary Differences	$ (188,213)	$ (180,662)
Amounts Due From Customers For Future Federal Income Taxes	(25,794)	(24,888)
Deferred State Income Taxes	(27,325)	(29,331)
Deferred Income Taxes on Other Comprehensive Loss	438	(836)
Deferred Fuel and Purchased Power	(1,617)	(410)
Accrued Pensions	(3,521)	(1,665)
All Other, Net	402	(4,341)
Net Deferred Tax Liabilities	$ (245,630)	$ (242,133)

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

KPCo and other AEP Subsidiaries are no longer subject to U.S. federal examination for years before 2000. However, KPCo and other AEP Subsidiaries have filed refund claims with the IRS for years 1997 through 2000 for the CSW pre-merger tax period, which are currently being reviewed. KPCo and other AEP Subsidiaries have completed the exam for the years 2001 through 2003 and have issues that will be pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on results of operations.

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

Prior to the adoption of FIN 48, KPCo recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48, KPCo began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Other Operation. In 2007, KPCo reported $300 thousand of interest expense and reversed $900 thousand of prior period interest expense. KPCo had approximately $1.3 million and $1.4 million for the payment of interest and penalties accrued at December 31, 2007 and 2006, respectively.

As a result of the implementation of FIN 48 on January 1, 2007, KPCo recognized a $786 thousand increase in the liabilities for unrecognized tax benefits, as well as related interest expense and penalties, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings.

As of December 31, 2007, the reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

		(in millions)
Balance at January 1, 2007	$	3.4
Increase - Tax Positions Taken During a Prior Period		-
Decrease - Tax Positions Taken During a Prior Period		(1.8)
Increase - Tax Positions Taken During the Current Year		0.6
Decrease - Settlements with Taxing Authorities		-
Decrease - Lapse of the Applicable Statute of Limitations		-
Balance at December 31, 2007	$	2.2

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $900 thousand. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

In 2005, the Energy Tax Incentives Act of 2005 was signed into law. This act created a limited amount of tax credits for the building of IGCC plants. The credit is 20% of the eligible property in the construction of new plant or 20% of the total cost of repowering of an existing plant using IGCC technology. In the case of a newly constructed IGCC plant, eligible property is defined as the components necessary for the gasification of coal, including any coal handling and gas separation equipment. AEP announced plans to construct two new IGCC plants that may be eligible for the allocation of these credits. AEP filed applications for the Mountaineer and Great Bend projects with the DOE and the IRS. Both projects were certified by the DOE and qualified by the IRS. However, neither project was awarded credits during this round of credit awards. AEP will continue to pursue credits for the next round of available credits.

The Tax Increase Prevention and Reconciliation Act of 2005 (TIPRA 2005) was passed May 17, 2006. The majority of the provisions in TIPRA 2005 were directed toward individual income tax relief including the extension of reduced tax rates for dividends and capital gains through 2010. Management believes the application of this act will not materially affect KPCo's results of operations, cash flow or financial condition.

The President signed the Pension Protection Act of 2006 (PPA 2006) into law on August 17, 2006. This law is directed toward strengthening qualified retirement plans and adding new restrictions on charitable contributions. Specifically, PPA 2006 concentrates on the funding of defined benefit plans and the health of the Pension Benefit Guaranty Corporation. PPA 2006 imposes new minimum funding rules for multiemployer plans as well as increasing the deduction limitation for contributions to multiemployer defined benefit plans. Due to the significant funding of the AEP pension plans in 2005, the Act will not materially affect KPCo's results of operations, cash flows or financial condition.

On December 20, 2006, the Tax Relief and Health Care Act of 2006 (TRHCA 2006) was signed into law. The primary purpose of the bill was to extend expiring tax provisions for individuals and business taxpayers and provide increased tax flexibility around medical benefits. In addition to extending the lower capital gains and dividend tax rates for individuals, TRHCA 2006 extended the research credit and for 2007 provided a new alternative formula for determining the research credit. The application of TRHCA 2006 is not expected to materially affect KPCo's results of operations, cash flows or financial condition.

Several tax bills and other legislation with tax-related sections were enacted in 2007, including the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007 and the Energy Independence and Security Act of 2007. The tax law changes enacted in 2007 are not expected to materially affect KPCo's results of operations, cash flows or financial condition.

State Tax Legislation

On June 30, 2005, the Governor of Ohio signed Ohio House Bill 66 into law enacting sweeping tax changes impacting all companies doing business in Ohio. Most of the significant tax changes will be phased in over a five-year period, while some of the less significant changes became fully effective July 1, 2005. Changes to the Ohio franchise tax, nonutility property taxes and the new commercial activity tax are subject to phase-in. The Ohio franchise tax will fully phase-out over a five-year period beginning with a 20% reduction in state franchise tax for taxable income accrued during 2005. In 2005, KPCo reversed $3.6 million of SFAS 109 Regulatory Assets and deferred state income tax liabilities that are not expected to reverse during the phase-out.

The new legislation also imposes a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The new tax is being phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate.

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

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

11. LEASES

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

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

	Years Ended December 31,		
	2007	2006	2005
Lease Rental Costs		(in thousands)	
Net Lease Expense on Operating Leases	$ 2,405	$ 2,079	$ 1,735
Amortization of Capital Leases	1,141	1,207	1,519
Interest on Capital Leases	140	116	34
Total Lease Rental Costs	$ 3,686	$ 3,402	$ 3,288

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 Current Liabilities – Other and Noncurrent Liabilities – Deferred Credits and Other on KPCo's Balance Sheets.

	December 31, 2007	December 31, 2006
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Production	$ 22	$ 436
Other	5,261	6,723
Total Property, Plant and Equipment Under Capital Leases	5,283	7,159
Accumulated Amortization	3,039	4,512
Net Property, Plant and Equipment Under Capital Leases	**$ 2,244**	**$ 2,647**
Obligations Under Capital Leases		
Noncurrent Liability	$ 1,272	$ 1,493
Liability Due Within One Year	972	1,154
Total Obligations Under Capital Leases	**$ 2,244**	**$ 2,647**

Future minimum lease payments consisted of the following at December 31, 2007:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2008	$ 1,056	$ 2,463
2009	647	2,218
2010	407	2,069
2011	180	1,667
2012	85	1,223
Later Years	58	2,933
Total Future Minimum Lease Payments	$ 2,433	$ 12,573
Less Estimated Interest Element	189	
Estimated Present Value of Future Minimum Lease Payments	$ 2,244	

12. 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, 2007 and 2006:

Type of Debt	Maturity	Interest Rates at December 31, 2007	Interest Rates at December 31, 2006	December 31, 2007	December 31, 2006
				(in thousands)	
Senior Unsecured Notes, Series B	2007	-	4.3148%	-	80,400
Senior Unsecured Notes, Series C	2007	-	4.368%	-	69,564
Senior Unsecured Notes, Series A	2007	-	5.50%	-	125,000
Senior Unsecured Medium Term Notes, Series A	2007	-	6.91%	-	48,000
Senior Unsecured Medium Term Notes, Series A	2008	6.45%	6.45%	30,000	30,000
Senior Unsecured Notes, Series E	2017	6.00%	-	325,000	-
Senior Unsecured Notes, Series D	2032	5.625%	5.625%	75,000	75,000
MTM of Fair Value Hedge				-	(916)
Unamortized Premium (Discount)				(1,627)	(80)
Total Senior Unsecured Notes				428,373	426,968
Notes Payable – Affiliated	2015	5.25%	5.25%	20,000	20,000
Total Notes Payable – Affiliated				20,000	20,000
Total Long-term Debt				448,373	446,968
Less: Long-term Debt Due Within One Year				30,000	322,048
Long-term Debt				$ 418,373	$ 124,920

At December 31, 2007 future annual long-term debt payments are as follows:

	2008	2009	2010	2011	2012	After 2012	Total
				(in thousands)			
Principal Amount	$ 30,000	$ -	$ -	$ -	$ -	$ 420,000	$ 450,000
Unamortized Discount							(1,627)
Total Long-term Debt							$ 448,373

Lines of Credit – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding loans (borrowings) to/from the Utility Money Pool as of December 31, 2007 and 2006 are included in Advances to/from Affiliates on KPCo's balance sheets. KPCo's Utility Money Pool activity and corresponding authorized borrowing limits for the years ended December 31, 2007 and 2006 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2007	$ 164,913	$ 181,970	$ 59,104	$ 115,727	$ 19,153	$ 250,000
2006	46,156	11,993	25,994	4,384	30,636	200,000

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2007, 2006 and 2005 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2007	5.92%	5.29%	5.94%	5.16%	5.50%	5.58 %
2006	5.41%	3.32%	5.12%	4.19%	4.74%	4.97 %
2005	4.49%	2.68%	4.45%	1.63%	3.70%	2.70 %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, in 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, 2007, 2006 and 2005:

	Years Ended December 31, 2007	2006	2005
	(in thousands)		
Interest Expense	$ 2,494	$ 1,065	$ 18
Interest Income	1,614	30	287

Dividend Restrictions

Under the Federal Power Act, KPCo is restricted from paying dividends out of stated capital.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash. This transaction constitutes a sale of receivables in accordance with SFAS 140, "Accounting for Transfers and Servicing of Financial Assets and Extinguishment of Liabilities," allowing the receivables to be taken off of AEP Credit's balance sheet and allowing AEP Credit to repay any debt obligations. AEP has no ownership interest in the commercial paper conduits and is not required to consolidate these entities in accordance with GAAP. AEP Credit continues to service the receivables. This off-balance sheet transaction was entered into to allow AEP Credit to repay its outstanding debt obligations, continue to purchase the AEP operating companies' receivables, and accelerate AEP Credit's cash collections.

In October 2007, AEP renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $650 million from banks and commercial paper conduits to purchase receivables from AEP Credit. Under the agreement, the commitment will increase to $700 million for the months of August and September to accommodate seasonal demand. This agreement will expire in October 2008. AEP intends to extend or replace the sale of receivables agreement. The previous sale of receivables agreement, which expired in August 2007 and was extended until October 2007, provided a commitment of $600 million from a bank conduit to purchase receivables from AEP Credit. At December 31, 2007, $507 million of commitments to purchase accounts receivable were outstanding under the receivables agreement. AEP Credit maintains a retained interest in the receivables sold and this interest is pledged as collateral for the collection of receivables sold. The fair value of the retained interest is based on book value due to the short-term nature of the accounts receivable less an allowance for anticipated uncollectible accounts. AEP Credit purchases accounts receivable through a purchase agreement with KPCo.

Comparative accounts receivable information for AEP Credit is as follows:

	Years Ended December 31, 2007	2006	2005
	($ in millions)		
Proceeds from Sale of Accounts Receivable	$ 6,970	$ 6,849	$ 5,925
Loss on Sale of Accounts Receivable	$ 33	$ 31	$ 18
Average Variable Discount Rate	5.39%	5.02%	3.23%

	December 31, 2007	2006
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 71	$ 87
Deferred Revenue from Servicing Accounts Receivable	1	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	68	85
Retained Interest if 20% Adverse Change in Uncollectible Accounts	66	83

Historical loss and delinquency amounts for the AEP System's customer accounts receivable managed portfolio is as follows:

	December 31, 2007	2006
	(in millions)	
Customer Accounts Receivable Retained	$ 730	$ 676
Accrued Unbilled Revenues Retained	379	350
Miscellaneous Accounts Receivable Retained	60	44
Allowance for Uncollectible Accounts Retained	(52)	(30)
Total Net Balance Sheet Accounts Receivable	1,117	1,040
Customer Accounts Receivable Securitized	507	536
Total Accounts Receivable Managed	$ 1,624	$ 1,576
Net Uncollectible Accounts Written Off	$ 24	$ 31

Customer accounts receivable retained and securitized for the domestic electric operating companies are managed by AEP Credit. Miscellaneous accounts receivable have been fully retained and not securitized.

Delinquent customer accounts receivable for the electric utility affiliates that AEP Credit currently factors were $30 million and $29 million at December 31, 2007 and 2006, respectively. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

Under the factoring 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 financing costs, its uncollectible accounts experience receivables and administrative costs. The costs of factoring customer accounts receivable are reported in Other Operation of the KPCo's Statements of Income.

KPCo's factored accounts receivable and accrued unbilled revenues were $41.4 million and $44 million as of December 31, 2007 and 2006, respectively.

KPCo paid fees to AEP Credit for factoring customer accounts receivable of $3.8 million, $3.4 million and $2.9 million for the years ended December 31, 2007, 2006 and 2005, respectively.

13. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Lines of Credit – AEP System" and "Sale of Receivables-AEP Credit" sections of Note 12.

AEP System Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member-load-ratio," which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

Power, gas and risk management activities are conducted by the AEP Power Pool and profits/losses are shared among the parties under the System Integration Agreement. Risk management activities involve the purchase and sale of electricity and gas under physical forward contracts at fixed and variable prices. In addition, the risk management of electricity, and to a lesser extent gas contracts, includes exchange traded futures and options and over-the-counter options and swaps. The majority of these transactions represent physical forward contracts in the AEP System's traditional marketing area and are typically settled by entering into offsetting contracts. In addition, the AEP Power Pool enters into transactions for the purchase and sale of electricity and gas options, futures and swaps, and for the forward purchase and sale of electricity outside of the AEP System's traditional marketing area.

System Integration Agreement (SIA)

AEP's System Integration Agreement, which has been approved by the FERC, provides for the integration and coordination of AEP's East companies and 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). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within each zone.

In November 2005, AEP filed with the FERC a proposed amendment to the SIA to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method causes such profits to be allocated generally on the basis of the zone in which the underlying transactions occur or originate. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006 and was approved as filed effective April 1, 2006.

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

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

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES, and other revenues for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	**2006**	**2005**
Related Party Revenues		**(in thousands)**	
Sales to East System Pool	$ 56,708	$ 57,921	$ 49,791
Direct Sales to West Affiliates	3,738	4,801	6,122
Natural Gas Contracts with AEPES	(197)	(4,698)	14,586
Other	302	263	304
Total Revenues	$ 60,551	$ 58,287	$ 70,803

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2007, 2006 and 2005:

	Years Ended December 31,		
	2007	2006	2005
Related Party Purchases	(in thousands)		
Purchases from East System Pool	$ 96,997	$ 99,166	$ 95,187
Direct Purchases from East Affiliates	88,051	92,881	81,163
Direct Purchases from West Affiliates	351	33	-
Total Purchases	$ 185,399	$ 192,080	$ 176,350

The above summarized related party revenues and expenses are reported as Sales to AEP Affiliates and Purchased Electricity from AEP Affiliates on KPCo's income statements.

AEP System Transmission Pool

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

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

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

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TEA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's "member-load-ratio."

KPCo's net credits as allocated under the TEA during the years ended December 31, 2007, 2006 and 2005 were $800 thousand, $2 million and $3.5 million, respectively, and were recorded in Other Operation on KPCo's income statements.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. 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 AEP West companies.

Natural Gas Contracts with DETM

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Beginning in 2007, PSO and SWEPCo were allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies and PSO and SWEPCo. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. There is no impact to the AEP consolidated financial statements. KPCo's risk management liabilities related to DETM at December 31, 2007 and 2006 were $1.9 million and $2.7 million, respectively.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with those two parties to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. KPCo's related purchases of gas managed by AEPES were $930 thousand, $398 thousand and $924 thousand for the years ended December 31, 2007, 2006 and 2005, respectively.

These purchases are reflected in Purchased Electricity for Resale on KPCo's income statements.

Unit Power Agreements (UPA)

A unit power agreement 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. 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) for such amounts, as when added to amounts received by AEGCo from any other sources, will be at least 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 unit power agreement 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 has agreed to pay 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 unit power agreement ends in December 2022. See Affiliated Revenues and Purchases section of this note.

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 costs of $80 thousand, $68 thousand and $133 thousand in 2007, 2006 and 2005, respectively, for urea transloading provided by I&M. These costs were recorded as fuel expense or operation expense.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its balance sheet the cost of performing the services, then transfers the cost to the affiliate for reimbursement. KPCo recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $167 thousands, $181 thousand and $285 thousand for the years ended December 31, 2007, 2006 and 2005, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of affiliate's 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 records these costs or reimbursements as costs or reduction of costs, respectively, 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 2007 and 2006 balance sheets:

	December 31,	
	2007	2006
Billing Company	(in thousands)	
APCo	$ 90	$ 384
OPCo	183	233

I&M Urea Translоading

I&M provides urea transloading services to KPCo. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded costs paid to I&M for barging services as Fuel and Other Consumables Used for Electric Generation in the amount of $80 thousand, $68 thousand and $133 thousand for the years ended December 31, 2007, 2006 and 2005, respectively.

AEP Power Pool Purchases from OVEC

Beginning in 2006, the AEP Power Pool began purchasing power from OVEC as part of wholesale marketing and risk management activity. These purchases are reflected in Electric Generation, Transmission and Distribution revenues in KPCo's Statements of Income. The current agreement will expire in May 2008. KPCo recorded $2 million and $2.7 million for the years ended December 31, 2007 and 2006, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more, for the years ended December 31, 2007, 2006 and 2005 as shown in the following table:

	Years Ended December 31,		
	2007	2006	2005
Companies		(in thousands)	
OPCo to KPCo	$ 133	$ -	$ -
KPCo to APCo	-	191	-
KPCo to OPCo	-	-	101

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2007, 2006 and 2005 as shown in the following table:

	APCO	CSPCo	I&M	KGPCo	OPCo	PSO	SWEPCo	TCC	WPCo	TOTAL
Sales					(in thousands)					
2007	$ 345	$ 38	$ 21	$ 10	$ 124	$ 85	$ 7	$ -	$ 66	$ 696
2006	2,178	75	40	11	254	28	-	3	9	2,598
2005	381	1	-	1	135	-	-	-	-	518
Purchases										
2007	$ 518	6	$ 4	$ 1	$ 197	$ -	$ -	$ -	$ 5	$ 731
2006	3,206	1	18	-	504	-	-	-	3	3,732
2005	1,577	8	22	-	304	-	-	-	-	1,911

The amounts above are recorded in Property, Plant and Equipment. Transfers are performed at cost.

Global Borrowing Notes

AEP issued long-term debt, a portion of which was loaned to KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's balance sheets. AEP pays the interest on the global notes, but KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Other in the Current Liabilities section of KPCo's balance sheets. KPCo participated in the global borrowing arrangement during the reporting periods.

AEPSC

AEPSC provides certain managerial and professional services to AEP System companies. The costs of the services are billed to KPCo by AEPSC on a direct-charge basis, whenever possible, and on reasonable bases 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, which is furnished to AEPSC by AEP. Billings from AEPSC are capitalized or expensed depending on the nature of the services rendered and are recoverable from customers. During 2005, AEPSC and its billings were subject to regulation by the SEC under the PUHCA of 1935. Effective February 8, 2006, the PUHCA of 2005 was enacted, which repealed the PUHCA of 1935 and transferred the regulatory responsibility from the SEC to the FERC.

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 bases 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. Billings are capitalized or expensed depending on the nature of the services rendered.

14. 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 table provides the annual composite depreciation rates by functional class:

2007	Regulated				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)
Production	$ 482,653	$ 168,806	3.8%	40-50	$ -	$ -	-%	-
Transmission	402,259	131,115	1.7%	25-75	-	-	-	-
Distribution	502,486	136,528	3.4%	11-75	-	-	-	-
CWIP	46,439	(1,463)	N.M.	N.M.	-	-	-	-
Other	56,173	21,867	8.7%	N.M.	5,492	175	N.M.	N.M.
Total	$ 1,490,010	$ 456,853			$ 5,492	$ 175		

2006	Regulated				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)
Production	$ 478,955	$ 161,172	3.8%	40-50	$ -	$ -	-%	-
Transmission	394,419	124,709	1.7%	25-75	-	-	-	-
Distribution	481,083	138,578	3.4%	11-75	-	-	-	-
CWIP	29,587	(1,785)	N.M.	N.M.	-	-	-	-
Other	55,544	19,918	9.6%	N.M.	5,545	186	N.M.	N.M.
Total	$ 1,439,588	$ 442,592			$ 5,545	$ 186		

2005	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Production	3.8%	40-50	-%	-
Transmission	1.7%	25-75	-	-
Distribution	3.5%	11-75	-	-
Other	9.4%	N.M.	2.0	N.M.

N.M. = 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 implemented SFAS 143 effective January 1, 2003. SFAS 143 requires entities to record a liability at fair value for any legal obligations for future asset retirements when the related assets are acquired or constructed. Upon establishment of a legal liability, SFAS 143 requires a corresponding ARO asset to be established, which will be depreciated over its useful life. Upon settlement of an ARO, KPCo recognizes any difference between the ARO liability and actual costs as income or expense.

KPCo adopted FIN 47 during the fourth quarter of 2005. FIN 47 interprets the application of SFAS 143. It clarifies that conditional ARO refers to a legal obligation to perform an asset retirement activity in which the timing and/or method of settlement are conditional on a future event that may or may not be within the control of the entity. Entities are required to record a liability for the fair value of a conditional ARO if the fair value of the liability can be reasonably estimated. FIN 47 also clarifies when an entity would have sufficient information to reasonably estimate the fair value of an ARO.

KPCo completed a review of its FIN 47 conditional ARO and concluded that legal liabilities exist for asbestos removal and disposal in general buildings and generating plants. In 2005, KPCo recorded a liability for conditional ARO of $1.2 million in accordance with FIN 47.

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 2007 and 2006 aggregate carrying amounts of ARO for KPCo:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2007	$ 1,175	$ 63	$ -	$ (294)	$ -	$ 944
2006	1,190	74	-	(89)	-	1,175

KPCo's aggregate carrying amounts include ARO related to ash ponds and asbestos removal.

Allowance for Funds Used During Construction (AFUDC)

The amounts of AFUDC included in Allowance For Equity Funds Used During Construction on KPCo's Statements of Income was $0.2 million, $0.2 million and $0.3 million for December 31, 2007, 2006 and 2005, respectively.

The amounts of allowance for borrowed funds used during construction included in Interest Expense on KPCo's Statements of Income was $0.6 million, $0.7 million and $0.3 million for December 31, 2007, 2006 and 2005, respectively.

15. 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:

	2007 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
		(in thousands)		
Operating Revenues	$ 154,096	$ 134,530	$ 152,200	$ 147,174
Operating Income	30,535	7,702	16,815	19,788
Net Income	15,211	1,230	6,485	9,544

	2006 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
		(in thousands)		
Operating Revenues	$ 151,847	$ 135,303	$ 152,319	$ 146,398
Operating Income	22,524	13,554	21,846	23,701
Net Income	9,830	5,051	9,869	10,285

There were no significant events in the fourth quarter of 2007 or 2006.

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

Form 1 Approved
OMB No. 1902-0021
(Expires 12/31/2011)
Form 1-F Approved
OMB No. 1902-0029
(Expires 12/31/2011)
Form 3-Q Approved
OMB No. 1902-0205
(Expires 1/31/2012)

RECEIVED
DEC 29 2009
PUBLIC SERVICE COMMISSION

KPSC Case No. 2009-00459
Pursuant to 807 KAR5:001
Section 10 (6) (m)
2008 FERC Form 1

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 2008/Q4

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

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

GENERAL INFORMATION

I. Purpose

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

II. Who Must Submit

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

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

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

III. What and Where to Submit

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

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

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

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

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

The CPA Certification Statement should:

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

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

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

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

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

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

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

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

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

IV. When to Submit:

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

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

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

V. Where to Send Comments on Public Reporting Burden.

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

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

GENERAL INSTRUCTIONS

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

DEFINITIONS

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

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

EXCERPTS FROM THE LAW

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

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

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

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

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

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

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

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

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

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

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

General Penalties

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

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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 2008/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 Stephen J. Clark	06 Title of Contact Person Senior Staff Accountant
07 Address of Contact Person *(Street, City, State, Zip Code)* AEP Service Corp., 1 Riverside Plaza, 26th Flr, Columbus, OH 43215-2373	

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

ANNUAL CORPORATE OFFICER CERTIFICATION

The undersigned officer certifies that:

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

01 Name Scott M. Krawec 02 Title Assistant Controller	03 Signature Scott M. Krawec	04 Date Signed *(Mo, Da, Yr)* 04/17/2009

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

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

LIST OF SCHEDULES (Electric Utility)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
1	General Information	101	
2	Control Over Respondent	102	
3	Corporations Controlled by Respondent	103	NA
4	Officers	104	
5	Directors	105	
6	Important Changes During the Year	108-109	
7	Comparative Balance Sheet	110-113	
8	Statement of Income for the Year	114-117	
9	Statement of Retained Earnings for the Year	118-119	
10	Statement of Cash Flows	120-121	
11	Notes to Financial Statements	122-123	
12	Statement of Accum Comp Income, Comp Income, and Hedging Activities	122(a)(b)	
13	Summary of Utility Plant & Accumulated Provisions for Dep, Amort & Dep	200-201	
14	Nuclear Fuel Materials	202-203	NA
15	Electric Plant in Service	204-207	
16	Electric Plant Leased to Others	213	NA
17	Electric Plant Held for Future Use	214	
18	Construction Work in Progress-Electric	216	
19	Accumulated Provision for Depreciation of Electric Utility Plant	219	
20	Investment of Subsidiary Companies	224-225	NA
21	Materials and Supplies	227	
22	Allowances	228-229	
23	Extraordinary Property Losses	230	NA
24	Unrecovered Plant and Regulatory Study Costs	230	NA
25	Transmission Service and Generation Interconnection Study Costs	231	
26	Other Regulatory Assets	232	
27	Miscellaneous Deferred Debits	233	
28	Accumulated Deferred Income Taxes	234	
29	Capital Stock	250-251	
30	Other Paid-in Capital	253	
31	Capital Stock Expense	254	NA
32	Long-Term Debt	256-257	
33	Reconciliation of Reported Net Income with Taxable Inc for Fed Inc Tax	261	
34	Taxes Accrued, Prepaid and Charged During the Year	262-263	
35	Accumulated Deferred Investment Tax Credits	266-267	
36	Other Deferred Credits	269	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

LIST OF SCHEDULES (Electric Utility) (continued)

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

Line No.	Title of Schedule (a)	Reference Page No. (b)	Remarks (c)
37	Accumulated Deferred Income Taxes-Accelerated Amortization Property	272-273	
38	Accumulated Deferred Income Taxes-Other Property	274-275	
39	Accumulated Deferred Income Taxes-Other	276-277	
40	Other Regulatory Liabilities	278	
41	Electric Operating Revenues	300-301	
42	Sales of Electricity by Rate Schedules	304	
43	Sales for Resale	310-311	
44	Electric Operation and Maintenance Expenses	320-323	
45	Purchased Power	326-327	
46	Transmission of Electricity for Others	328-330	
47	Transmission of Electricity by ISO/RTOs	331	NA
48	Transmission of Electricity by Others	332	
49	Miscellaneous General Expenses-Electric	335	
50	Depreciation and Amortization of Electric Plant	336-337	
51	Regulatory Commission Expenses	350-351	
52	Research, Development and Demonstration Activities	352-353	
53	Distribution of Salaries and Wages	354-355	
54	Common Utility Plant and Expenses	356	NA
55	Amounts included in ISO/RTO Settlement Statements	397	
56	Purchase and Sale of Ancillary Services	398	
57	Monthly Transmission System Peak Load	400	
58	Monthly ISO/RTO Transmission System Peak Load	400a	NA
59	Electric Energy Account	401	
60	Monthly Peaks and Output	401	
61	Steam Electric Generating Plant Statistics	402-403	
62	Hydroelectric Generating Plant Statistics	406-407	NA
63	Pumped Storage Generating Plant Statistics	408-409	NA
64	Generating Plant Statistics Pages	410-411	NA
65	Transmission Line Statistics Pages	422-423	
66	Transmission Lines Added During the Year	424-425	

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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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	Substations	426-427	
68	Footnote Data	450	
	Stockholders' Reports Check appropriate box: [X] Four copies will be submitted [ ] No annual report to stockholders is prepared		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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.

Scott M. Krawec, Assistant Controller
1 Riverside Plaza
Columbus, OH 43215

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

Kentucky
July 21, 1919

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

None

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

Electric - Kentucky

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CONTROL OVER RESPONDENT

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

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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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Schedule Page: 104 Line No.: 1 Column: a

Executive Compensation Table

The following table shows the compensation earned by the chief executive officer and the four other most highly compensated executive officers of AEP at December 31, 2008:

Name and Principal Position (a)	Salary ($) (b)	Stock Awards ($)(1) (c)	Non-Equity Incentive Plan Compensation ($)(2) (d)	Change in Pension Value and Non-qualified Deferred Compensation Earnings ($)(3) (e)	All Other Compensation ($)(4) (f)	Total ($) (g)
Michael G. Morris — Chairman of the board, president and chief executive officer	1,259,615	(43,132)	1,654,071	330,564	818,438	4,019,556
Holly Keller Koeppel — Executive vice president and chief financial officer	503,846	(43,316)	450,000	168,745	68,342	1,147,617
Carl L. English — Chief operating officer	554,231	(130,697)	450,000	88,541	69,837	1,031,912
Brian X. Tierney — Executive vice president	403,077	8,234	665,000	117,421	61,134	1,254,866
Robert P. Powers — President-AEP Utilities	513,923	(117,629)	415,000	175,962	84,475	1,071,731

(1) The amounts reported in this column are the expense recognized or reversed in our financial statements pursuant to FASB 123R for stock awards granted in the current and prior years. The amounts shown in this column were negative for Messrs. Morris, English and Powers and Ms Koeppel, which is primarily due to the decline in our stock price. The negative amounts are the result of our performance unit awards being classified as liabilities for financial reporting purposes, which requires us to re-measure the cost of such awards at each financial statement reporting date. As a result, the performance unit compensation costs recognized by the Company and attributed to each executive officer for purposes of this column will fluctuate from year to year based on AEP's stock price and other factors.

For Messrs. Morris and English, this column also includes the expense for restricted stock and restricted stock units granted in 2004 and 2005, which were granted upon their hire. These awards were granted as replacements for certain long-term compensation that they forfeited from a prior employer and as an inducement to accept our employment offer.

(2) The amounts shown in this column are annual incentive awards made under the Company's Senior Officer Incentive Plan for the year shown. At the outset of each year, the HR Committee sets target bonuses and performance criteria that will be used to determine whether and to what extent executive officers will receive payments under this plan.

(3) The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer's combined benefits under AEP's qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company's financial statements. No named executive officer received preferential or above-market earnings on deferred compensation.

(4) A detailed breakout of the amounts shown in the All Other Compensation column is shown below. These amounts include subsidiary director fees, tax gross-ups, and Company contributions to the Company's Retirement Savings Plan and the Company's Supplemental Retirement Savings Plan. This column also includes $142,206 of premiums for life insurance that the Company funds on Mr. Morris' behalf and a tax gross-up payment of $99,693 to Mr. Morris on the value of this benefit.

For Mr. Morris, Ms. Koeppel and Mr. Powers, the amount shown includes the aggregate incremental cost associated with their personal use of Company provided aircraft of $443,916, $4,375 and $9,949, respectively. This amount is the incremental cost to the Company for their personal use of Company-provided aircraft, including all operating costs such as fuel, trip-related maintenance, on-board catering, landing/ramp fees and other miscellaneous variable costs. Fixed costs that do not change based on usage, such as pilot salaries, the lease costs for Company aircraft and the cost of maintenance not related to personal trips, are excluded. Personal use of corporate aircraft includes the incremental cost of relocating aircraft to accommodate personal trips and the incremental costs of flights for Mr. Morris and Ms. Koeppel to attend outside board meetings for the public companies at which they serve as outside directors.

The Company reimbursed executives for expenses for spouse travel to events that the Company invited the executive's spouse to attend. A tax gross-up on the value of such spousal travel in Company aircraft is included under tax gross-ups below. The Company does not gross-up for expenses when executives travel for personal purposes.

Other Compensation

Type	Michael G. Morris	Holly Keller Koeppel	Carl L. English	Brian X. Tierney	Robert P. Powers
Retirement Savings Plan Match	$7,362	$7,393	$10,350	$10,350	$10,167
Supplemental Retirement Savings Plan Match	82,638	33,011	32,324	40,193	30,745
Tax Gross-Ups (a)	104,362	3,850	799	2,460	4,061
Subsidiary Company Directors Fees	14,850	14,750	11,400	7,850	11,200
Life and Director Accident Insurance	142,206	—	—	—	—
Country and Dining Club Dues and Airline Club Dues	2,065	2,013	2,264	281	7,265
Financial Counseling and Tax Preparation	20,950	2,950	12,700	—	11,088
Personal Use of Company Aircraft	443,916	4,375	—	—	9,949
Personal Services of Employees	89	—	—	—	—

(a) Of the amount shown for Mr. Morris, $99,693 relates to a gross-up provided on life insurance.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	Michael G. Morris, Chairman of the Board	Columbus, Ohio
2	Chief Executive Officer	
3		
4	Nicholas K. Akins, Vice President	Columbus, Ohio
5		
6	Carl L. English, Vice President	Columbus, Ohio
7		
8	John B. Keane	Columbus, Ohio
9		
10	Holly K. Koeppel, Chief Financial Officer	Columbus, Ohio
11	Vice President	
12		
13	Richard E. Munczinski, Vice President	Columbus, Ohio
14		
15	Robert P. Powers, Vice Chairman of the Board	Columbus, Ohio
16	Vice President	
17		
18	Stephen P. Smith, Vice President	Columbus, Ohio
19	Treasurer	
20		
21	Brian X. Tierney, Vice Chairman of the Board	Columbus, Ohio
22	Vice President	
23		
24	Susan Tomasky, Vice President	Columbus, Ohio
25		
26	Dennis E. Welch, Vice President	Columbus, Ohio
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29	Note: The Respondent does not have an Executive Committee	
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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 106, voting trustee, associated company or known associate of any of these persons was a party or in which any such person had a material interest.
11. (Reserved.)
12. If the important changes during the year relating to the respondent company appearing in the annual report to stockholders are applicable in every respect and furnish the data required by Instructions 1 to 11 above, such notes may be included on this page.
13. Describe fully any changes in officers, directors, major security holders and voting powers of the respondent that may have occurred during the reporting period.
14. In the event that the respondent participates in a cash management program(s) and its proprietary capital ratio is less than 30 percent please describe the significant events or transactions causing the proprietary capital ratio to be less than 30 percent, and the extent to which the respondent has amounts loaned or money advanced to its parent, subsidiary, or affiliated companies through a cash management program(s). Additionally, please describe plans, if any to regain at least a 30 percent proprietary ratio.

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

1.

Date Acquired Or Extended	Community	Period of Franchise & Termination	Consideration
Renewed on May 13, 2008	City of Paintsville, Johnson County, Kentucky	Twenty year (20) franchise renewal, expiring on May 12, 2028	Annual sum equal to 25% of the total amount, excluding any applicable tax and/or any applied fuel clause adjustment, paid by the City for street lighting purposes during the preceding 12 months
Renewed on June 17, 2008	City of Wheelwright, Floyd County, Kentucky	Twenty (20) year franchise renewal, expiring on June 16, 2028	Annual sum equal to 25% of the total amount, excluding any applicable tax and/or any applied fuel clause adjustment, paid by the City for street lighting purposes during the preceding 12 months

2. None

3. None

4. None

5. None

6. None

7. None

8. Wage agreements for 2008 resulted in general increase of 3.1% for represented employees.

9. None

10. None

11. (Reserved)

12. Not Used

13. Stephen P. Smith resigned as Treasurer effective January 1, 2008

    Stephen T. Haynes resigned as Assistant Treasurer effective January 29, 2008

    Robert P. Powers resigned as Vice Chairman of the Board effective January 29, 2008

    Julia A. Sloat appointed as Treasurer effective January 1, 2008

    Renee V. Hawkins appointed as Assistant Treasurer effective January 29, 2008

    Brian X. Tierney appointed as Director, Vice Chairman of the Board and Vice President effective January 29, 2008

    Stephen P. Smith resigned as Director and Vice President effective June 1, 2008

    Scott M. Krawec appointed as Assistant Controller effective April 15, 2008

    Richard E. Munczinski appointed as Director and Vice President effective June 26, 2008

    William F. Vineyard appointed as Vice President effective May 1, 2008

    Julia A. Sloat resigned as Treasurer effective July 10, 2008

    Charles E. Zebula resigned as Vice President effective September 1, 2008

    Timothy K. Light appointed as Vice President effective September 1, 2008

    Charles E. Zebula appointed as Treasurer effective September 1, 2008

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	/ /	End of 2008/Q4

COMPARATIVE BALANCE SHEET (ASSETS AND OTHER DEBITS)

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
1	**UTILITY PLANT**			
2	Utility Plant (101-106, 114)	200-201	1,552,385,107	1,440,533,191
3	Construction Work in Progress (107)	200-201	46,649,955	46,438,535
4	TOTAL Utility Plant (Enter Total of lines 2 and 3)		1,599,035,062	1,486,971,726
5	(Less) Accum. Prov. for Depr. Amort. Depl. (108, 110, 111, 115)	200-201	506,112,000	486,924,033
6	Net Utility Plant (Enter Total of line 4 less 5)		1,092,923,062	1,000,047,693
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)		1,092,923,062	1,000,047,693
15	Utility Plant Adjustments (116)	122	0	0
16	Gas Stored Underground - Noncurrent (117)		0	0
17	**OTHER PROPERTY AND INVESTMENTS**			
18	Nonutility Property (121)		957,608	958,217
19	(Less) Accum. Prov. for Depr. and Amort. (122)		177,553	170,884
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	6,698,929	7,726,305
24	Other Investments (124)		4,877,555	4,952,097
25	Sinking Funds (125)		0	0
26	Depreciation Fund (126)		0	0
27	Amortization Fund - Federal (127)		0	0
28	Other Special Funds (128)		0	0
29	Special Funds (Non Major Only) (129)		0	11,893,302
30	Long-Term Portion of Derivative Assets (175)		10,821,797	14,780,188
31	Long-Term Portion of Derivative Assets – Hedges (176)		38,529	46,105
32	TOTAL Other Property and Investments (Lines 18-21 and 23-31)		23,216,865	40,185,330
33	**CURRENT AND ACCRUED ASSETS**			
34	Cash and Working Funds (Non-major Only) (130)		0	0
35	Cash (131)		641,031	722,442
36	Special Deposits (132-134)		5,207,298	1,263,146
37	Working Fund (135)		5,000	5,000
38	Temporary Cash Investments (136)		0	0
39	Notes Receivable (141)		0	0
40	Customer Accounts Receivable (142)		17,245,233	16,694,930
41	Other Accounts Receivable (143)		2,374,342	2,669,697
42	(Less) Accum. Prov. for Uncollectible Acct.-Credit (144)		1,144,287	1,070,770
43	Notes Receivable from Associated Companies (145)		0	0
44	Accounts Receivable from Assoc. Companies (146)		5,604,460	15,156,245
45	Fuel Stock (151)	227	29,070,196	8,174,520
46	Fuel Stock Expenses Undistributed (152)	227	370,203	163,093
47	Residuals (Elec) and Extracted Products (153)	227	0	0
48	Plant Materials and Operating Supplies (154)	227	8,814,925	9,076,539
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	8,514,372	10,407,420

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		6,698,929	7,726,305
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)		1,270,714	1,424,017
58	Advances for Gas (166-167)		0	0
59	Interest and Dividends Receivable (171)		1,716,000	0
60	Rents Receivable (172)		2,145,094	1,009,522
61	Accrued Utility Revenues (173)		2,532,686	2,903,820
62	Miscellaneous Current and Accrued Assets (174)		0	0
63	Derivative Instrument Assets (175)		23,503,560	26,738,329
64	(Less) Long-Term Portion of Derivative Instrument Assets (175)		10,821,797	14,780,188
65	Derivative Instrument Assets - Hedges (176)		1,116,452	208,420
66	(Less) Long-Term Portion of Derivative Instrument Assets - Hedges (176		38,529	46,105
67	Total Current and Accrued Assets (Lines 34 through 66)		91,428,024	72,993,772
68	**DEFERRED DEBITS**			
69	Unamortized Debt Expenses (181)		2,700,800	2,831,845
70	Extraordinary Property Losses (182.1)	230	0	0
71	Unrecovered Plant and Regulatory Study Costs (182.2)	230	0	0
72	Other Regulatory Assets (182.3)	232	191,782,108	131,939,930
73	Prelim. Survey and Investigation Charges (Electric) (183)		21,020,444	21,642,135
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	11,719,579	10,547,844
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)		804,762	838,410
82	Accumulated Deferred Income Taxes (190)	234	56,518,797	35,036,862
83	Unrecovered Purchased Gas Costs (191)		0	0
84	Total Deferred Debits (lines 69 through 83)		284,546,490	202,837,026
85	TOTAL ASSETS (lines 14-16, 32, 67, and 84)		1,492,114,441	1,316,063,821

Name of Respondent	This Report is:	Date of Report (mo, da, yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Rresubmission	/ /	end of 2008/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)	252	0	0
5	Stock Liability for Conversion (203, 206)	252	0	0
6	Premium on Capital Stock (207)	252	0	0
7	Other Paid-In Capital (208-211)	253	208,750,000	208,750,000
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)	254	0	0
11	Retained Earnings (215, 215.1, 216)	118-119	138,749,089	128,583,536
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)	59,584	-813,548
16	Total Proprietary Capital (lines 2 through 15)		398,008,673	386,969,988
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	400,000,000	430,000,000
22	Unamortized Premium on Long-Term Debt (225)		0	0
23	(Less) Unamortized Discount on Long-Term Debt-Debit (226)		1,444,950	1,627,300
24	Total Long-Term Debt (lines 18 through 23)		418,555,050	448,372,700
25	OTHER NONCURRENT LIABILITIES			
26	Obligations Under Capital Leases - Noncurrent (227)		1,045,188	1,271,691
27	Accumulated Provision for Property Insurance (228.1)		0	0
28	Accumulated Provision for Injuries and Damages (228.2)		42,487	11,324
29	Accumulated Provision for Pensions and Benefits (228.3)		51,776,694	13,783,380
30	Accumulated Miscellaneous Operating Provisions (228.4)		0	0
31	Accumulated Provision for Rate Refunds (229)		0	0
32	Long-Term Portion of Derivative Instrument Liabilities		5,624,396	9,671,489
33	Long-Term Portion of Derivative Instrument Liabilities - Hedges		6,097	27,596
34	Asset Retirement Obligations (230)		3,274,611	944,128
35	Total Other Noncurrent Liabilities (lines 26 through 34)		61,769,473	25,709,608
36	CURRENT AND ACCRUED LIABILITIES			
37	Notes Payable (231)		0	0
38	Accounts Payable (232)		35,583,784	32,603,316
39	Notes Payable to Associated Companies (233)		131,398,655	19,153,141
40	Accounts Payable to Associated Companies (234)		45,332,844	29,524,166
41	Customer Deposits (235)		15,984,420	14,422,815
42	Taxes Accrued (236)	262-263	13,026,485	16,981,490
43	Interest Accrued (237)		7,493,652	8,139,481
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 Rresubmission	/ /	end of 2008/Q4

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

Line No.	Title of Account (a)	Ref. Page No. (b)	Current Year End of Quarter/Year Balance (c)	Prior Year End Balance 12/31 (d)
46	Matured Interest (240)		0	0
47	Tax Collections Payable (241)		2,061,863	1,450,853
48	Miscellaneous Current and Accrued Liabilities (242)		19,981,175	16,700,453
49	Obligations Under Capital Leases-Current (243)		776,743	971,780
50	Derivative Instrument Liabilities (244)		11,704,026	19,423,753
51	(Less) Long-Term Portion of Derivative Instrument Liabilities		5,624,396	9,671,489
52	Derivative Instrument Liabilities - Hedges (245)		242,107	585,021
53	(Less) Long-Term Portion of Derivative Instrument Liabilities-Hedges		6,097	27,596
54	Total Current and Accrued Liabilities (lines 37 through 53)		277,955,261	150,257,184
55	DEFERRED CREDITS			
56	Customer Advances for Construction (252)		67,543	84,783
57	Accumulated Deferred Investment Tax Credits (255)	266-267	2,519,320	3,394,506
58	Deferred Gains from Disposition of Utility Plant (256)		0	0
59	Other Deferred Credits (253)	269	4,085,819	5,855,609
60	Other Regulatory Liabilities (254)	278	14,530,176	13,458,021
61	Unamortized Gain on Reaquired Debt (257)		0	0
62	Accum. Deferred Income Taxes-Accel. Amort.(281)	272-277	32,792,379	31,958,064
63	Accum. Deferred Income Taxes-Other Property (282)		183,129,281	166,064,531
64	Accum. Deferred Income Taxes-Other (283)		98,701,466	83,938,827
65	Total Deferred Credits (lines 56 through 64)		335,825,984	304,754,341
66	TOTAL LIABILITIES AND STOCKHOLDER EQUITY (lines 16, 24, 35, 54 and 65)		1,492,114,441	1,316,063,821

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STATEMENT OF INCOME

Quarterly
1. Enter in column (d) the balance for the reporting quarter and in column (e) the balance for the same three month period for the prior year.
2. Report in column (f) the quarter to date amounts for electric utility function; in column (h) the quarter to date amounts for gas utility, and in (j) the quarter to date amounts for other utility function for the current year quarter.
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 (k) the quarter to date amounts for other utility function for the prior year quarter.
4. 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.
8. Report data for lines 8, 10 and 11 for Natural Gas companies using accounts 404.1, 404.2, 404.3, 407.1 and 407.2.

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	692,226,601	606,969,066		
3	Operating Expenses					
4	Operation Expenses (401)	320-323	517,091,523	432,451,700		
5	Maintenance Expenses (402)	320-323	47,920,449	36,969,210		
6	Depreciation Expense (403)	336-337	43,555,013	42,384,728		
7	Depreciation Expense for Asset Retirement Costs (403.1)	336-337				
8	Amort. & Depl. of Utility Plant (404-405)	336-337	3,864,022	3,947,772		
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)		609,525	822,369		
13	(Less) Regulatory Credits (407.4)					
14	Taxes Other Than Income Taxes (408.1)	262-263	9,644,218	11,872,166		
15	Income Taxes - Federal (409.1)	262-263	3,618,871	11,756,073		
16	- Other (409.1)	262-263	1,571,395	1,132,195		
17	Provision for Deferred Income Taxes (410.1)	234, 272-277	59,159,999	51,676,144		
18	(Less) Provision for Deferred Income Taxes-Cr. (411.1)	234, 272-277	54,128,901	46,242,658		
19	Investment Tax Credit Adj. - Net (411.4)	266	-875,186	-1,006,540		
20	(Less) Gains from Disp. of Utility Plant (411.6)		1,861	1,637		
21	Losses from Disp. of Utility Plant (411.7)					
22	(Less) Gains from Disposition of Allowances (411.8)		680,383	3,143,983		
23	Losses from Disposition of Allowances (411.9)			1,259		
24	Accretion Expense (411.10)		-1,275			
25	TOTAL Utility Operating Expenses (Enter Total of lines 4 thru 24)		631,386,025	542,657,414		
26	Net Util Oper Inc (Enter Tot line 2 less 25) Carry to Pg117,line 27		60,840,576	64,311,652		

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

STATEMENT OF INCOME FOR THE YEAR (Continued)

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

ELECTRIC UTILITY		GAS UTILITY		OTHER UTILITY		Line No.
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)	
						1
692,226,601	606,969,066					2
						3
517,091,523	432,451,700					4
47,920,449	36,969,210					5
43,555,013	42,384,728					6
						7
3,864,022	3,947,772					8
38,616	38,616					9
						10
						11
609,525	822,369					12
						13
9,644,218	11,872,166					14
3,618,871	11,756,073					15
1,571,395	1,132,195					16
59,159,999	51,676,144					17
54,128,901	46,242,658					18
-875,186	-1,006,540					19
1,861	1,637					20
						21
680,383	3,143,983					22
	1,259					23
-1,275						24
631,386,025	542,657,414					25
60,840,576	64,311,652					26

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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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)		60,840,576	64,311,652		
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)		45,005	45,255		
36	Equity in Earnings of Subsidiary Companies (418.1)	119				
37	Interest and Dividend Income (419)		1,930,498	1,807,996		
38	Allowance for Other Funds Used During Construction (419.1)		1,012,376	259,559		
39	Miscellaneous Nonoperating Income (421)		-541,927	-1,311,016		
40	Gain on Disposition of Property (421.1)					
41	TOTAL Other Income (Enter Total of lines 31 thru 40)		2,445,952	801,794		
42	Other Income Deductions					
43	Loss on Disposition of Property (421.2)		178,014			
44	Miscellaneous Amortization (425)	340				
45	Donations (426.1)	340	1,735,037	1,069,864		
46	Life Insurance (426.2)					
47	Penalties (426.3)		-74,738	1,019,294		
48	Exp. for Certain Civic, Political & Related Activities (426.4)		436,375	182,444		
49	Other Deductions (426.5)		3,395,517	3,186,799		
50	TOTAL Other Income Deductions (Total of lines 43 thru 49)		5,670,205	5,458,401		
51	Taxes Applic. to Other Income and Deductions					
52	Taxes Other Than Income Taxes (408.2)	262-263				
53	Income Taxes-Federal (409.2)	262-263	-594,617	-1,630,706		
54	Income Taxes-Other (409.2)	262-263	78,426			
55	Provision for Deferred Inc. Taxes (410.2)	234, 272-277	872,496	4,190,482		
56	(Less) Provision for Deferred Income Taxes-Cr. (411.2)	234, 272-277	1,806,937	3,932,994		
57	Investment Tax Credit Adj.-Net (411.5)			44,855		
58	(Less) Investment Tax Credits (420)					
59	TOTAL Taxes on Other Income and Deductions (Total of lines 52-58)		-1,450,632	-1,328,363		
60	Net Other Income and Deductions (Total of lines 41, 50, 59)		-1,773,621	-3,328,244		
61	Interest Charges					
62	Interest on Long-Term Debt (427)		25,472,581	24,199,988		
63	Amort. of Debt Disc. and Expense (428)		451,645	1,020,433		
64	Amortization of Loss on Reaquired Debt (428.1)		33,648	50,519		
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)	340	8,771,116	3,555,977		
68	Other Interest Expense (431)	340	1,507,355	282,422		
69	(Less) Allowance for Borrowed Funds Used During Construction-Cr. (432)		1,700,711	595,488		
70	Net Interest Charges (Total of lines 62 thru 69)		34,535,634	28,513,851		
71	Income Before Extraordinary Items (Total of lines 27, 60 and 70)		24,531,321	32,469,557		
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)		24,531,321	32,469,557		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
	UNAPPROPRIATED RETAINED EARNINGS (Account 216)			
1	Balance-Beginning of Period		128,583,536	108,899,709
2	Changes			
3	Adjustments to Retained Earnings (Account 439)			
4				
5				
6				
7				
8				
9	TOTAL Credits to Retained Earnings (Acct. 439)			
10	Adoption of FASB Interpretation No 48, Net of tax $243,780	Various		(785,730)
11	Adoption of EITF 06-10, Net of tax $196,952	923,926	-365,768	
12				
13				
14				
15	TOTAL Debits to Retained Earnings (Acct. 439)		-365,768	(785,730)
16	Balance Transferred from Income (Account 433 less Account 418.1)		24,531,321	32,469,557
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	238	-14,000,000	(12,000,000)
32				
33				
34				
35				
36	TOTAL Dividends Declared-Common Stock (Acct. 438)		-14,000,000	(12,000,000)
37	Transfers from Acct 216.1, Unapprop. Undistrib. Subsidiary Earnings			
38	Balance - End of Period (Total 1,9,15,16,22,29,36,37)		138,749,089	128,583,536
	APPROPRIATED RETAINED EARNINGS (Account 215)			

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

STATEMENT OF RETAINED EARNINGS

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

Line No.	Item (a)	Contra Primary Account Affected (b)	Current Quarter/Year Year to Date Balance (c)	Previous Quarter/Year Year to Date Balance (d)
39				
40				
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)		138,749,089	128,583,536
	UNAPPROPRIATED UNDISTRIBUTED SUBSIDIARY EARNINGS (Account			
	Report only on an Annual Basis, no Quarterly			
49	Balance-Beginning of Year (Debit or Credit)			
50	Equity in Earnings for Year (Credit) (Account 418.1)			
51	(Less) Dividends Received (Debit)			
52				
53	Balance-End of Year (Total lines 49 thru 52)			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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)	24,531,321	32,469,557
3	Noncash Charges (Credits) to Income:		
4	Depreciation and Depletion	47,457,651	46,371,116
5	Amortization of Regulatory Debits and Credits (Net)	609,525	822,369
6			
7	Mark to Market of Risk Management Contracts	-4,650,225	88,457
8	Deferred Income Taxes (Net)	4,096,657	5,690,974
9	Investment Tax Credit Adjustment (Net)	-875,186	-961,685
10	Net (Increase) Decrease in Receivables	6,371,782	1,694,334
11	Net (Increase) Decrease in Inventory	-20,841,172	6,462,888
12	Net (Increase) Decrease in Allowances Inventory	1,893,049	-822,982
13	Net Increase (Decrease) in Payables and Accrued Expenses	16,834,182	892,005
14	Net (Increase) Decrease in Other Regulatory Assets	-934,545	1,983,671
15	Net Increase (Decrease) in Other Regulatory Liabilities	1,783,156	-3,654,452
16	(Less) Allowance for Other Funds Used During Construction	1,012,376	259,559
17	(Less) Undistributed Earnings from Subsidiary Companies		
18	Other (provide details in footnote):	-10,830,255	4,033,267
19	Customer Deposits	1,561,606	1,368,997
20	Over/Under Recovered Fuel (Net)	-5,527,700	-3,383,207
21			
22	Net Cash Provided by (Used in) Operating Activities (Total 2 thru 21)	60,467,470	92,795,750
23			
24	Cash Flows from Investment Activities:		
25	Construction and Acquisition of Plant (including land):		
26	Gross Additions to Utility Plant (less nuclear fuel)	-130,630,781	-68,393,389
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	-1,012,376	-259,559
31	Acquired Assets Subject to Lease-back	-314,250	
32			
33			
34	Cash Outflows for Plant (Total of lines 26 thru 33)	-129,932,655	-68,133,830
35			
36	Acquisition of Other Noncurrent Assets (d)		
37	Proceeds from Disposal of Noncurrent Assets (d)	947,088	695,238
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 Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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	48,582	14,767
52	Net Increase (Decrease) in Payables and Accrued Expenses		
53	Other (provide details in footnote):		
54			
55			
56	Net Cash Provided by (Used in) Investing Activities		
57	Total of lines 34 thru 55)	-128,936,985	-67,423,825
58			
59	Cash Flows from Financing Activities:		
60	Proceeds from Issuance of:		
61	Long-Term Debt (b)		325,000,000
62	Preferred Stock		
63	Common Stock		
64	Other (provide details in footnote):		
65	Long Term Issuances Costs		-3,899,753
66	Net Increase in Short-Term Debt (c)		
67	Proceeds from acquired assets subject to Capital Lease	142,590	
68	Notes Payable to Associated Companies	112,245,514	
69			
70	Cash Provided by Outside Sources (Total 61 thru 69)	112,388,104	321,100,247
71			
72	Payments for Retirement of:		
73	Long-term Debt (b)	-30,000,000	-322,964,000
74	Preferred Stock		
75	Common Stock		
76	Other (provide details in footnote):		
77	Notes Payable to Associated Companies		-11,482,721
78	Net Decrease in Short-Term Debt (c)		
79			
80	Dividends on Preferred Stock		
81	Dividends on Common Stock	-14,000,000	-12,000,000
82	Net Cash Provided by (Used in) Financing Activities		
83	(Total of lines 70 thru 81)	68,388,104	-25,346,474
84			
85	Net Increase (Decrease) in Cash and Cash Equivalents		
86	(Total of lines 22,57 and 83)	-81,411	25,451
87			
88	Cash and Cash Equivalents at Beginning of Period	727,442	701,991
89			
90	Cash and Cash Equivalents at End of period	646,031	727,442

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

	2008	2007
Utility Plant, Net	(10,529,059)	(4,517,195)
Property and Investments, Net	33,238	40,007
Margin Deposits	(3,944,152)	1,222,215
Derivative Instruments, Net	(1,250,946)	2,765,766
Prepayments	1,087,247	923,779
Accrued Utility Revenues, Net	371,134	698,597
Unamortized Debt Expense	131,045	854,478
Other Deferred Debits, Net	(516,395)	482,181
Other Comprehensive Income - FAS 133	873,132	(2,365,708)
Unamortized Discount/Premium on Long-Term Debt	182,350	119,575
Accumulated Provisions - Misc	875,877	182,722
Current and Accrued Liabilities, Net	2,378,410	93,984
Other Deferred Credits, Net	(522,136)	3,532,866
Total Other	(10,830,255)	4,033,267

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

	2008	2007
Sales of transformers to various associated companies	138,059	102,002
Sales of meters to various associated companies	405,152	593,236
Sale of Hays Branch-Morgan Fork property	232,217	-
Proceeds from acquired assets subject to Operating Lease	171,660	-
Total Sales of Property	947,088	695,238

Name of Respondent	This Report Is:	Date of Report	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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.

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SEE PAGE 123 FOR REQUIRED INFORMATION.

INDEX OF NOTES TO FINANCIAL STATEMENTS

GLOSSARY OF TERMS FOR NOTES

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
AEP Credit	AEP Credit, Inc., a subsidiary of AEP which factors accounts receivable and accrued utility revenues for affiliated electric utility companies.
AEP East companies	APCo, CSPCo, I&M, KPCo and OPCo.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Power Pool	Members are APCo, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
ALJ	Administrative Law Judge.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
ARO	Asset Retirement Obligations.
CAA	Clean Air Act.
CO_2	Carbon Dioxide.
CSPCo	Columbus Southern Power Company, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, by and among PSO, SWEPCo, TCC and TNC governing generating capacity allocation. This agreement was amended in May 2006 to remove TCC and TNC. AEPSC acts as the agent.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
EIS	Energy Insurance Services, Inc., a protected cell insurance company that AEP consolidates due to FIN 46R.
EITF	Financial Accounting Standards Board's Emerging Issues Task Force.
EITF 06-10	EITF Issue No. 06-10 "Accounting for Collateral Assignment Split-Dollar Life Insurance Arrangements."
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
FASB	Financial Accounting Standards Board.

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
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FIN	FASB Interpretation No.
FIN 48	FIN 48, "Accounting for Uncertainty in Income Taxes" and FASB Staff Position FIN 48-1 "Definition of *Settlement* in FASB Interpretation No. 48."
FSP	FASB Staff Position.
FSP FIN 39-1	FSP FIN 39-1, "Amendment of FASB Interpretation No. 39."
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.
KGPCo	Kingsport Power Company, an AEP electric distribution subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
MISO	Midwest Independent Transmission System Operator.
MTM	Mark-to-Market.
MW	Megawatt.
NO_X	Nitrogen oxide.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
Property, Plant and Equipment	Includes Utility Plant and Nonutility Property.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization.
SECA	Seams Elimination Cost Allocation.
SFAS	Statement of Financial Accounting Standards issued by the Financial Accounting Standards Board.
SFAS 71	Statement of Financial Accounting Standards No. 71, "Accounting for the Effects of Certain Types of Regulation."
SFAS 107	Statement of Financial Accounting Standards No. 107, "Disclosures about Fair Value of Financial Investments."

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
SFAS 109	Statement of Financial Accounting Standards No. 109, "Accounting for Income Taxes."
SFAS 133	Statement of Financial Accounting Standards No. 133, "Accounting for Derivative Instruments and Hedging Activities."
SFAS 157	Statement of Financial Accounting Standards No. 157, "Fair Value Measurements."
SFAS 158	Statement of Financial Accounting Standards No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans."
SIA	System Integration Agreement.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Utility Money Pool	AEP System's Utility Money Pool.
WPCo	Wheeling Power Company, an AEP electric distribution subsidiary.

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 176,000 retail customers in its service territory in eastern Kentucky. As a member of the AEP Power Pool, KPCo shares the revenues and the costs of the AEP Power Pool's sales to neighboring utilities and power marketers. KPCo also sells power at wholesale to municipalities.

The cost of the AEP Power Pool's generating capacity is allocated among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. AEP Power Pool members are also compensated for the out-of-pocket costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The AEP Power Pool calculates each member's prior twelve-month peak demand relative to the sum of the peak demands of all members as a basis for sharing revenues and costs. The result of this calculation is the member load ratio (MLR), which determines each member's percentage share of revenues and costs.

Under a unit power agreement with AEGCo, an affiliated company that is not a member of the AEP Power Pool, KPCo purchases 15% of the total output of the 2,600 MW Rockport Plant capacity. Therefore, KPCo purchases 390 MW 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 neighboring utilities, power marketers and other power and gas risk management activities based upon the location of such activity, with margins resulting from trading and marketing activities originating in PJM and MISO generally accruing to the benefit of the AEP East companies and trading and marketing activities originating in SPP and ERCOT generally accruing to the benefit of PSO and SWEPCo. Margins resulting from other transactions are allocated among the AEP East companies, PSO and SWEPCo in proportion to the marketing realization directly assigned to each zone for the current month plus the preceding eleven months.

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

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

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

The KPSC approves retail rates and regulates the retail services and operations for the generation and supply of power and retail transmission and distribution energy delivery services. KPCo's affiliated transactions, including AEPSC intercompany service billings which are generally at cost, are regulated by the FERC under the 2005 Public Utility Holding Company Act and the Federal Power Act and by the KPSC. The FERC also has jurisdiction over the issuances and acquisitions of securities, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. A FERC order in 2008 pursuant to the Federal Power Act codified that for non-power goods and services, a non-regulated affiliate can bill a public utility company no more than market while a public utility must bill the higher of cost or market to a non-regulated affiliate.

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission services. KPCo's wholesale power transactions are generally market-based. They 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 enters into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts.

In addition, the FERC regulates the SIA, the Interconnection Agreement, the System Transmission Integration Agreement, the Transmission Equalization Agreement and the AEP System Interim Allowance Agreement, all of which allocate shared system costs and revenues to the AEP subsidiaries that are parties to each agreement, including KPCo.

The FERC issued Order 715, "Revisions to Forms, Statements and Reporting Requirements for Electric Utilities and Licensees" in September 2008. The order amends the FERC's reporting requirements for public utilities associated with the FERC Form 1 and the FERC Form 3-Q. The revised reporting requirements are intended to enhance the FERC's and customers' review of formula rates, permit a better understanding of non-power goods and services transactions with affiliates and provide additional detail of revenues not previously specified in the FERC Form 1. The new rule takes effect January 1, 2009. Management is currently evaluating what efforts are necessary to comply with the new reporting requirements.

The KPSC regulates all of the retail public utility services/operations (generation/power supply, transmission and distribution operations) and rates for KPCo, which are cost-based. Both the FERC and the KPSC are permitted to review and audit the books and records of KPCo.

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 GAAP include:

- The classification of deferred fuel as noncurrent rather than current.
- The requirement to report deferred tax assets and liabilities separately rather than a single amount.
- The classification of accrued taxes as a single amount rather than assets and liabilities.
- The exclusion of current maturities of long-term debt from current liabilities.
- The classification of accrued non-ARO asset removal costs as accumulated depreciation rather than regulatory liabilities.
- The classification of 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 PJM hourly activity for physical transactions as purchases and sales instead of net sales.
- The classification of noncurrent tax liabilities and interest accrued related to FIN 48 as a current liability rather than a noncurrent liability.
- The classification of regulatory assets and liabilities associated with SFAS 109 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 expenses 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 other assets and liabilities as noncurrent instead of current.
- The classification of income tax expense on Net Utility Operating Income and on Net Other Income and Deductions instead of as a single net income tax.

Accounting for the Effects of Cost-Based Regulation

As a cost-based 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 SFAS 71, regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues.

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. 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, 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.

Property, Plant and Equipment and Equity Investments

Electric utility property, plant and equipment are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for cost-based rate-regulated operations under the group composite method of 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. 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 depreciation rates that are established for the generating plants 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 SFAS 144, "Accounting for the Impairment or Disposal of Long-lived Assets." 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 and investment is the amount at which that asset and investment could be bought or sold in a current transaction between willing parties, as opposed to a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets or investments in active markets, fair value is estimated using various internal and external valuation methods including cash flow analysis and appraisals.

Allowance for Funds Used During Construction (AFUDC)

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

Valuation of Nonderivative Financial Instruments

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

Cash and Cash Equivalents

Cash and Cash Equivalents on the Statement of Cash Flows include Cash and Working Fund on the Comparative Balance Sheet with original maturities of three months or less.

Supplementary Information

		2008		2007
For the Year Ended December 31,		**(in thousands)**		
Cash Was Paid for:				
Interest (Net of Capitalized Amounts)	$	28,602	$	28,864
Income Taxes (Net of Refunds)		3,554		10,477
Noncash Acquisitions Under Capital Leases		544		826
At December 31,				
Noncash Construction Expenditures Included in Accounts Payable		9,662		12,161
Revenue Refund Included in Accounts Payable		18,526		-

Special Deposits

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

Inventory

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

Accounts Receivable

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

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

AEP Credit factors accounts receivable for KPCo. AEP Credit has a sale of receivables agreement with banks and commercial paper conduits.

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, 2008 or 2007.

KPCo monitors credit levels and the financial condition of its 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 financial statements.

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the regulator's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of regulators. On a routine basis, the KPSC audits fuel cost calculations and deferrals. When a fuel cost disallowance becomes probable, KPCo adjusts its deferrals and records provisions for estimated refunds to recognize the probable outcomes. In general, changes in fuel costs are reflected in rates in a timely manner through the fuel cost adjustment clause. A portion of profits from off-system sales are shared with customers through the fuel clause.

Revenue Recognition

Regulatory Accounting

The 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 by matching expenses with their recovery through regulated revenues in the same accounting period and by matching income with its passage to customers in cost-based regulated rates. Regulatory liabilities or regulatory assets are also recorded for unrealized MTM gains or losses that occur due to changes in the fair value of physical and/or financial contracts that are derivatives and that are subject to the regulated ratemaking process when realized.

When regulatory assets are probable of recovery through regulated rates, KPCo records them as assets on the balance sheet. KPCo tests for probability of recovery at each balance sheet date or whenever new events occur. Examples 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.

Traditional 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 in the financial statements upon delivery of the energy to the customer and includes unbilled as well as billed amounts.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. The AEP East companies purchase power from PJM to supply power to customers. These power sales and purchases are reported on an hourly net basis. In hours where the AEP East companies are required to purchase more power than they sold into PJM to cover retail and wholesale customer obligations, KPCo's share of these amounts are reported in Operation Expenses. In hours where the AEP East companies sell more power than they purchased from PJM to cover retail and wholesale customer obligations, KPCo's share of these amounts are reported in Operating Revenues. Other RTOs function as balancing organizations and not as an exchange.

Physical energy purchases, including those from all RTOs that are identified as non-trading, but excluding PJM purchases described in the preceding paragraph are accounted for on a gross basis in Operation Expenses.

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

Energy Marketing and Risk Management Activities

AEPSC, on behalf of the AEP East companies, engages in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where the AEP System owns assets and adjacent markets. These activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts which include exchange traded futures and options, and over-the-counter options and swaps. 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. KPCo's unrealized gains and losses for both trading and non-trading derivative instruments are recorded as a regulatory asset (for losses) or a regulatory liability (for gains). Realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses depending on the relevant facts and circumstances.

KPCo includes realized gains and losses on wholesale marketing and risk management transactions where the AEP System owns assets or in adjacent markets in Operating Revenues. The realized gains and losses for certain legacy transactions executed outside of the AEP System are reported as Miscellaneous Nonoperating Income.

Certain qualifying wholesale marketing and risk management 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 Accumulated Other Comprehensive Income into revenues or expenses within the same financial statement line item as the forecasted transaction. KPCo defers the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains). See "Cash Flow Hedging Strategies" section of Note 8.

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 FIN 48. Effective with the adoption of FIN 48 beginning January 1, 2007, 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

KPCo, as an agent for some state and local governments, collects from customers certain excise taxes levied by those state or local governments on customers. KPCo does not record 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 associated with the regulated business is refinanced, the reacquisition costs attributable to the portions of the business that are subject to cost-based regulatory accounting 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.

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. Allowances held for speculation are included in Other Investments. Gains or losses on sale of emission allowances held speculatively are recorded in Miscellaneous Nonoperating Income and Other Deductions, respectively. The purchases and sales of allowances are reported in the Operating Activities section of the Statement of Cash Flows except speculative allowance transactions which are reported in Investing Activities. The net margin on sales of emission allowances affects the determination of deferred fuel costs and the amortization of regulatory assets.

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.

Reclassifications

Certain prior period financial statement items have been reclassified to conform to current period presentation. See FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" section of Note 2 for discussion of changes in netting certain balance sheet amounts. These reclassifications had no impact on KPCo's previously reported net income.

2. NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, management reviews the new accounting literature to determine the relevance, if any, to KPCo's business. The following represents a summary of final pronouncements that management has determined relate to KPCo's operations.

Pronouncements Adopted in 2008

The following standards were effective during 2008. Consequently, the financial statements and footnotes reflect their impact.

SFAS 157 "Fair Value Measurements" (SFAS 157)

KPCo partially adopted SFAS 157 effective January 1, 2008. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures.

In February 2008, the FASB issued FSP SFAS 157-1 "Application of FASB Statement No. 157 to FASB Statement No. 13 and Other Accounting Pronouncements That Address Fair Value Measurements for Purposes of Lease Classification or Measurement under Statement 13" (SFAS 157-1) which amends SFAS 157 to exclude SFAS 13 "Accounting for Leases" and other accounting pronouncements that address fair value measurements for purposes of lease classification or measurement under SFAS 13. SFAS 157-1 was effective upon issuance and had an immaterial impact on the financial statements.

In February 2008, the FASB issued FSP SFAS 157-2 "Effective Date of FASB Statement No. 157" (SFAS 157-2) which delays the effective date of SFAS 157 to fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). KPCo fully adopted SFAS 157 effective January 1, 2009 for items within the scope of SFAS 157-2. The adoption of SFAS 157-2 had an immaterial impact on the financial statements.

In October 2008, the FASB issued FSP SFAS 157-3 "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active" which clarifies application of SFAS 157 in markets that are not active and provides an illustrative example. The FSP was effective upon issuance. The adoption of this standard had no impact on the financial statements.

See "SFAS 157 Fair Value Measurements" Section of Note 8 for further information.

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

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

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

SFAS 162 "The Hierarchy of Generally Accepted Accounting Principles" (SFAS 162)

In May 2008, the FASB issued SFAS 162, clarifying the sources of generally accepted accounting principles in descending order of authority. The statement specifies that the reporting entity, not its auditors, is responsible for its compliance with GAAP.

KPCo adopted SFAS 162 in the fourth quarter of 2008. The adoption of this standard had no impact on the financial statements.

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

In March 2007, the FASB ratified EITF 06-10, a consensus on collateral assignment split-dollar life insurance arrangements in which an employee owns and controls the insurance policy. Under EITF 06-10, an employer should recognize a liability for the postretirement benefit related to a collateral assignment split-dollar life insurance arrangement if the employer agreed to maintain a life insurance policy during the employee's retirement or to provide the employee with a death benefit based on a substantive arrangement with the employee. In addition, an employer should recognize and measure an asset based on the nature and substance of the collateral assignment split-dollar life insurance arrangement. EITF 06-10 requires recognition of the effects of its application as either (a) a cumulative effect adjustment to retained earnings or other components of equity or net assets in the statement of financial position at the beginning of the year of adoption or (b) retrospective application to all prior periods. KPCo adopted EITF 06-10 effective January 1, 2008 with a cumulative effect reduction of $562 thousand, ($365 thousand, net of tax) to beginning retained earnings.

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

In June 2007, the FASB addressed the recognition of income tax benefits of dividends on employee share-based compensation. Under EITF 06-11, a realized income tax benefit from dividends or dividend equivalents that are charged to retained earnings and are paid to employees for equity-classified nonvested equity shares, nonvested equity share units and outstanding equity share options should be recognized as an increase to additional paid-in capital.

KPCo adopted EITF 06-11 effective January 1, 2008. The adoption of this standard had an immaterial impact on the financial statements.

FSP SFAS 133-1 and FIN 45-4 "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161" (FSP SFAS 133-1 and FIN 45-4)

In September 2008, the FASB issued FSP SFAS 133-1 and FIN 45-4 amending SFAS 133 and FIN 45 "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others." Under the SFAS 133 requirements, the seller of a credit derivative shall disclose the following information for each derivative, including credit derivatives embedded in a hybrid instrument, even if the likelihood of payment is remote:

(a) The nature of the credit derivative.
(b) The maximum potential amount of future payments.
(c) The fair value of the credit derivative.
(d) The nature of any recourse provisions and any assets held as collateral or by third parties.

Further, the standard requires the disclosure of current payment status/performance risk of all FIN 45 guarantees. In the event an entity uses internal groupings, the entity shall disclose how those groupings are determined and used for managing risk.

KPCo adopted the standard effective December 31, 2008. The adoption of this standard had no impact on the financial statements and footnote disclosures.

FSP FIN 39-1 "Amendment of FASB Interpretation No. 39" (FSP FIN 39-1)

In April 2007, the FASB issued FSP FIN 39-1 amending FIN 39, "Offsetting of Amounts Related to Certain Contracts" by replacing the interpretation's definition of contracts with the definition of derivative instruments per SFAS 133. The amendment requires entities that offset fair values of derivatives with the same party under a netting agreement to net the fair values (or approximate fair values) of related cash collateral. The entities must disclose whether or not they offset fair values of derivatives and related cash collateral and amounts recognized for cash collateral payables and receivables at the end of each reporting period.

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

Balance Sheet Line Description	As Reported for December 2007	FSP FIN 39-1 Reclassification	As Reported for December 2008
		(in thousands)	
Special Deposits	$ 1,940	$ (677)	$ 1,263
Derivative Instrument Assets	27,628	(890)	26,738
Long-term Portion of Derivative Instrument Assets	15,310	(530)	14,780
Customer Deposits	15,312	(890)	14,422
Derivative Instrument Liabilities	20,101	(677)	19,424
Long-term Portion of Derivative Instrument Liabilities	9,683	(12)	9,671

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, 2008 balance sheet, KPCo netted $468 thousand of cash collateral received from third parties against short-term and long-term risk management assets and $1.2 million of cash collateral paid to third parties against short-term and long-term risk management liabilities.

Pronouncements Adopted During The First Quarter of 2009

The following standards are effective during the first quarter of 2009. Consequently, their impact will be reflected in the first quarter of 2009 financial statements. The following paragraphs discuss their expected impact on future financial statement and footnote disclosures.

SFAS 141 (revised 2007) "Business Combinations" (SFAS 141R)

In December 2007, the FASB issued SFAS 141R, improving financial reporting about business combinations and their effects. It established how the acquiring entity recognizes and measures the identifiable assets acquired, liabilities assumed, goodwill acquired, any gain on bargain purchases and any noncontrolling interest in the acquired entity. SFAS 141R no longer allows acquisition-related costs to be included in the cost of the business combination, but rather expensed in the periods they are incurred, with the exception of the costs to issue debt or equity securities which shall be recognized in accordance with other applicable GAAP. The standard requires disclosure of information for a business combination that occurs during the accounting period or prior to the issuance of the financial statements for the accounting period. SFAS 141R can affect tax positions on previous acquisitions. KPCo does not have any such tax positions that result in adjustments.

KPCo adopted SFAS 141R effective January 1, 2009. It is effective prospectively for business combinations with an acquisition date on or after January 1, 2009. KPCo will apply it to any future business combinations.

SFAS 161 "Disclosures about Derivative Instruments and Hedging Activities" (SFAS 161)

In March 2008, the FASB issued SFAS 161, enhancing disclosure requirements for derivative instruments and hedging activities. Affected entities are required to provide enhanced disclosures about (a) how and why an entity uses derivative instruments, (b) how an entity accounts for derivative instruments and related hedged items and (c) how derivative instruments and related hedged items affect an entity's financial position, financial performance and cash flows. The standard requires that objectives for using derivative instruments be disclosed in terms of underlying risk and accounting designation.

KPCo adopted SFAS 161 effective January 1, 2009. This standard will increase the disclosure requirements related to derivative instruments and hedging activities in future reports.

EITF Issue No. 08-5 "Issuer's Accounting for Liabilities Measured at Fair Value with a Third-Party Credit Enhancement" (EITF 08-5)

In September 2008, the FASB ratified the consensus on liabilities with third-party credit enhancements when the liability is measured and disclosed at fair value. The consensus treats the liability and the credit enhancement as two units of accounting. Under the consensus, the fair value measurement of the liability does not include the effect of the third-party credit enhancement. Consequently, changes in the issuer's credit standing without the support of the credit enhancement affect the fair value measurement of the issuer's liability. Entities will need to provide disclosures about the existence of any third-party credit enhancements related to their liabilities. In the period of adoption, entities must disclose the valuation method(s) used to measure the fair value of liabilities within its scope and any change in the fair value measurement method that occurs as a result of its initial application.

KPCo adopted EITF 08-5 effective January 1, 2009. It will be applied prospectively with the effect of initial application included as a change in fair value of the liability in the period of adoption. The adoption of this standard will impact the financial statements in the 2009 Annual Report as KPCo reports fair value of long-term debt annually.

EITF Issue No. 08-6 "Equity Method Investment Accounting Considerations" (EITF 08-6)

In November 2008, the FASB ratified the consensus on equity method investment accounting including initial and allocated carrying values and subsequent measurements. It requires initial carrying value be determined using the SFAS 141R cost allocation method. When an investee issues shares, the equity method investor should treat the transaction as if the investor sold part of its interest.

KPCo adopted EITF 08-6 effective January 1, 2009 with no impact on the financial statements. It was applied prospectively.

FSP SFAS 142-3 "Determination of the Useful Life of Intangible Assets" (SFAS 142-3)

In April 2008, the FASB issued SFAS 142-3 amending factors that should be considered in developing renewal or extension assumptions used to determine the useful life of a recognized intangible asset. The standard is expected to improve consistency between the useful life of a recognized intangible asset and the period of expected cash flows used to measure its fair value.

KPCo adopted SFAS 142-3 effective January 1, 2009. The guidance is prospectively applied to intangible assets acquired after the effective date. The standard's disclosure requirements are applied prospectively to all intangible assets as of January 1, 2009. The adoption of this standard had no impact on the financial statements.

Pronouncements Effective in the Future

The following standards will be effective in the future and their impacts disclosed at that time.

FSP SFAS 132R-1 "Employers' Disclosures about Postretirement Benefit Plan Assets" (FSP SFAS 132R-1)

In December 2008, the FASB issued FSP SFAS 132R-1 providing additional disclosure guidance for pension and OPEB plan assets. The rule requires disclosure of investment policy including target allocations by investment class, investment goals, risk management policies and permitted or prohibited investments. It specifies a minimum of investment classes by further dividing equity and debt securities by issuer grouping. The standard adds disclosure requirements including hierarchical classes for fair value and concentration of risk.

This standard is effective for fiscal years ending after December 15, 2009. Management expects this standard to increase the disclosure requirements related to AEP's benefit plans. KPCo will adopt the standard effective for the 2009 Annual Report.

Future Accounting Changes

The FASB's standard-setting process is ongoing and until new standards have been finalized and issued, management cannot determine the impact on the reporting of operations and financial position that may result from any such future changes. The FASB is currently working on several projects including revenue recognition, contingencies, liabilities and equity, emission allowances, leases, insurance, hedge accounting, trading inventory and related tax impacts. Management also expects to see more FASB projects as a result of its desire to converge International Accounting Standards with GAAP. The ultimate pronouncements resulting from these and future projects could have an impact on future net income and financial position.

3. RATE MATTERS

KPCo is involved in rate and regulatory proceedings at the FERC and the KPSC. This note is a discussion of rate matters and industry restructuring related proceedings that could have a material effect on net income and cash flows.

For discussion of the FERC's November 2008 order on AEP's allocation of off-system sales, see "Allocation of Off-system Sales Margins" section within "FERC Rate Matters".

Validity of Nonstatutory Surcharges

In August 2007, the Franklin County Circuit Court concluded the KPSC did not have the authority to order a surcharge for a gas company subsidiary of Duke Energy absent a full cost of service rate proceeding due to the lack of statutory authority. The Kentucky Attorney General (AG) notified the KPSC that the Franklin County Circuit Court judge's order in the Duke Energy case can be interpreted to include other existing surcharges, rates or fees established outside of the context of a general rate case proceeding and not specifically authorized by statute, including fuel clauses. Both the KPSC and Duke Energy appealed the Franklin County Circuit Court decision.

Although this order is not directly applicable, KPCo has existing surcharges which are not specifically authorized by statute. These include KPCo's fuel clause surcharge, the annual Rockport Plant capacity surcharge, the merger surcredit and the off-system sales credit rider. On an annual basis these surcharges recently ranged from revenues of approximately $10 million to a reduction of revenues of $2 million due to the volatility of these surcharges. The KPSC asked interested parties to brief the issue in KPCo's fuel cost proceeding. The AG responded that the KPCo fuel clause should be invalidated because the KPSC lacked the authority to implement a fuel clause for KPCo without a full rate case review. The KPSC issued an order stating that it has the authority to provide for surcharges and surcredits until the court of appeals rules otherwise.

In November 2008, the Kentucky Court of Appeals concluded that Duke Energy's surcharge was illegal. However, the order stated that the "decision was premised on the nature of the long-term capital improvements proposed by Duke Energy as distinguished from the fuel increases that are fluctuating and unanticipated. The latter have been approved by the Kentucky Supreme Court and remain the law". In February 2009, the Kentucky Court of Appeals denied the KPSC request for appeal of the Franklin County Circuit Court decision. Management believes that all of KPCo's variable rate mechanisms are valid and would be upheld if ever challenged.

2008 Fuel Cost Reconciliation

In January 2008, KPCo filed its semi-annual fuel cost reconciliation covering the period May 2007 through October 2007. As part of this filing, KPCo sought recovery of incremental costs associated with transmission line losses billed by PJM since June 2007 due to PJM's implementation of PJM transmission marginal line loss pricing. KPCo expensed these incremental PJM costs associated with transmission line losses pending a determination that they are recoverable through the Kentucky fuel clause. In June 2008, the KPSC issued an order approving KPCo's semi-annual fuel cost reconciliation filing and recovery of incremental costs associated with transmission line losses billed by PJM. For the year ended December 31, 2008, KPCo recorded $20 million of income and the related Other Regulatory Assets for transmission line losses incurred from June 2007 through December 2008 of which $7 million related to 2007.

FERC Rate Matters

Regional Transmission Rate Proceedings at the FERC

SECA Revenue Subject to Refund

Effective December 1, 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected at FERC's direction load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 31, 2006. Intervenors objected to the temporary SECA rates, raising various issues. As a result, the FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies paid SECA rates to other utilities at considerably lesser amounts than they collected. If a refund is ordered, the AEP East companies would also receive refunds related to the SECA rates they paid to third parties. The AEP East companies recognized gross SECA revenues of $220 million from December 2004 through March 2006 when the SECA rates terminated leaving the AEP East companies and ultimately their internal load retail customers to make up the short fall in revenues. KPCo's portion of recognized gross SECA revenues was $17 million.

In August 2006, a FERC ALJ issued an initial decision, finding that the rate design for the recovery of SECA charges was flawed and that a large portion of the "lost revenues" reflected in the SECA rates should not have been recoverable. The ALJ found that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that the unpaid SECA rates must be paid in the recommended reduced amount.

In September 2006, AEP filed briefs jointly with other affected companies noting exceptions to the ALJ's initial decision and asking the FERC to reverse the decision in large part. Management believes, based on advice of legal counsel, that the FERC should reject the ALJ's initial decision because it contradicts prior related FERC decisions, which are presently subject to rehearing. Furthermore, management believes the ALJ's findings on key issues are largely without merit. AEP and SECA ratepayers have engaged in settlement discussions in an effort to settle the SECA issue. However, if the ALJ's initial decision is upheld in its entirety, it could result in a disallowance of a large portion on any unsettled SECA revenues.

Based on anticipated settlements, the AEP East companies provided reserves for net refunds for current and future SECA settlements totaling $44 million applicable to a total of $220 million of SECA revenues. KPCo's portion of the provision was $3.3 million.

In December 2008, an additional settlement agreement was approved by the FERC resulting in the completion of a $2 million settlement applicable to $17 million of SECA revenue. Including this most recent settlement, AEP has completed settlements totaling $9 million applicable to $92 million of SECA revenues. The balance in the reserve for future settlements as of December 2008 was $35 million. KPCo's reserve balance at December 31, 2008 was $2.6 million. In-process settlements total $1 million applicable to $20 million of SECA revenues. In February 2009, the FERC approved the in-process settlements resulting in the completion of a $1 million settlement application to $20 million of SECA revenues. KPCo's reverse balance at December 31, 2008 was $2.6 million.

If the FERC adopts the ALJ's decision and/or AEP cannot settle all of the remaining unsettled claims within the remaining amount reserved for refund, it will have an adverse effect on future net income and cash flows. Based on advice of external FERC counsel, recent settlement experience and the expectation that most of the unsettled SECA revenues will be settled, management believes that the available reserve of $34 million is adequate to settle the remaining $108 million of contested SECA revenues. However, management cannot predict the ultimate outcome of ongoing settlement discussions or future FERC proceedings or court appeals, if any.

The FERC PJM Regional Transmission Rate Proceeding

With the elimination of T&O rates, the expiration of SECA rates and after considerable administrative litigation at the FERC in which AEP sought to mitigate the effect of the T&O rate elimination, the FERC failed to implement a regional rate in PJM. As a result, the AEP East companies' retail customers incur the bulk of the cost of the existing AEP east transmission zone facilities. However, the FERC ruled that the cost of any new 500 kV and higher voltage transmission facilities built in PJM would be shared by all customers in the region. It is expected that most of the new 500 kV and higher voltage transmission facilities will be built in other zones of PJM, not AEP's zone. The AEP East companies will need to obtain regulatory approvals for recovery of any costs of new facilities that are assigned to them by PJM. In February 2008, AEP filed a Petition for Review of the FERC orders in this case in the United States Court of Appeals. Management cannot estimate at this time what effect, if any, this order will have on the AEP East companies' future construction of new transmission facilities, net income and cash flows.

The AEP East companies filed for and in 2006 obtained increases in their wholesale transmission rates to recover lost revenues previously applied to reduce those rates. AEP has also sought and received retail rate increases in Ohio, Virginia, West Virginia and Kentucky. As a result, AEP is now recovering approximately 80% of the lost T&O transmission revenues. AEP received net SECA transmission revenues of $128 million in 2005.

The FERC PJM and MISO Regional Transmission Rate Proceeding

In the SECA proceedings, the FERC ordered the RTOs and transmission owners in the PJM/MISO region (the Super Region) to file, by August 1, 2007, a proposal to establish a permanent transmission rate design for the Super Region to be effective February 1, 2008. All of the transmission owners in PJM and MISO, with the exception of AEP and one MISO transmission owner, elected to support continuation of zonal rates in both RTOs. In September 2007, AEP filed a formal complaint proposing a highway/byway rate design be implemented for the Super Region where users pay based on their use of the transmission system. AEP argued the use of other PJM and MISO facilities by AEP is not as large as the use of AEP transmission by others in PJM and MISO. Therefore, a regional rate design change is required to recognize that the provision and use of transmission service in the Super Region is not sufficiently uniform between transmission owners and users to justify zonal rates. In January 2008, the FERC denied AEP's complaint. AEP filed a rehearing request with the FERC in March 2008. In December 2008, the FERC denied AEP's request for rehearing. In February 2009, AEP filed an appeal in the U.S. Court of Appeals. If the court appeal is successful, earnings could benefit for a certain period of time due to regulatory lag until the AEP East companies reduce future retail revenues in their next fuel or base rate proceedings. Management is unable to predict the outcome of this case.

PJM Transmission Formula Rate Filing

In July 2008, AEP filed an application with the FERC to increase its rates for wholesale transmission service within PJM by $63 million annually. The filing seeks to implement a formula rate allowing annual adjustments reflecting future changes in AEP's cost of service. The requested increase would result in a combined increase in annual revenues for the AEP East companies of approximately $9 million from nonaffiliated customers within PJM. The remaining $54 million requested would be billed to the AEP East companies but would be offset by compensation from PJM for use of AEP's transmission facilities so that retail rates are not affected. AEP requested an effective date of October 1, 2008. In September 2008, the FERC issued an order conditionally accepting AEP's proposed formula rate, subject to a compliance filing, suspended the effective date until March 1, 2009 and established a settlement proceeding with an ALJ. In October 2008, AEP began settlement discussions and filed the required compliance filing. Management is unable to predict the outcome of this filing.

Allocation of Off-system Sales Margins

In August 2008, the Corporation Commission of the State of Oklahoma filed a complaint at the FERC alleging that AEP inappropriately allocated off-system sales margins between the AEP East companies and the AEP West companies and did not properly allocate off-system sales margins within the AEP West companies. In November 2008, the FERC issued a final order concluding that AEP inappropriately deviated from off-system sales margin allocation methods in the AEP SIA and the CSW Operating Agreement for the period June 2000 through March 2006. The FERC ordered AEP to recalculate and reallocate the off-system sales margins in compliance with the AEP SIA and to have the AEP East companies issue refunds to the AEP West companies. In December 2008, AEP filed a motion for rehearing. The motion for rehearing is still pending. In January 2009, AEP filed a compliance filing with the FERC and refunded approximately $250 million from the AEP East companies to the AEP West companies.

The table below lists the respective amounts the AEP East companies and the AEP West companies recorded in December 2008 including the net increase (decrease) to net income for the year ended December 31, 2008:

AEP East Companies	Amounts to be (Transferred)/ Received Including Interest	Increase/ (Decrease) to Net Income
	(in millions)	
APCo	$ (77)	$ (50)
I&M	(48)	(32)
OPCo	(62)	(40)
CSPCo	(44)	(28)
KPCo	(19)	(12)
Total – AEP East Companies	(250)	(162)
AEP West Companies		
PSO	72	12
SWEPCo	85	20
TCC	68	23
TNC	25	10
Total – AEP West Companies	250	65
Total – AEP Consolidated	$ -	$ (97)

The table below shows the vintage year of the associated AEP SIA refunds:

	For the Twelve Months Ended December 31,			
AEP East Companies	2006 and Prior	2007	2008	Total
	(in millions)			
APCo	$ (66)	$ (6)	$ (5)	$ (77)
I&M	(41)	(4)	(3)	(48)
OPCo	(53)	(5)	(4)	(62)
CSPCo	(40)	(3)	(1)	(44)
KPCo	(17)	(1)	(1)	(19)
Total – AEP East Companies	(217)	(19)	(14)	(250)
AEP West Companies				
PSO	62	6	4	72
SWEPCo	74	6	5	85
TCC	59	5	4	68
TNC	22	2	1	25
Total – AEP West Companies	217	19	14	250
Total – AEP Consolidated	$ -	$ -	$ -	$ -

Management cannot predict the outcome of the requested FERC rehearing proceeding or any future regulatory proceedings but believes the provision regarding future regulatory proceedings is adequate.

Transmission Equalization Agreement

Certain transmission equipment placed in service in 1998 in KPCo's service territory was inadvertently excluded from the AEP East companies' TEA calculation. As a result, KPCo did not receive a TEA credit from the other TEA member companies to equalize its investment in this equipment. Management believes that it is not probable that a material retroactive adjustment will result from the omission. However, if a retroactive adjustment is required, it could have an effect on future net income, cash flows and financial condition.

4. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

	December 31, 2008	December 31, 2007	Notes
Regulatory Assets	(in thousands)		
SFAS 109 Regulatory Asset (See Note 9)	$ 110,742	$ 104,865	(a) (d)
SFAS 158 Regulatory Asset (See Note 6)	61,439	13,573	(a) (d)
Unrecovered Fuel Costs	9,953	4,426	(a) (g)
Other	9,648	9,076	(b) (d)
Total FERC Account 182.3 Regulatory Assets	$ 191,782	$ 131,940	
Unamortized Loss on Reacquired Debt (c)	$ 805	$ 838	(b) (e)
Regulatory Liabilities			
SFAS 109 Regulatory Liability (See Note 9)	$ 2,789	$ 3,525	(a) (d)
Unrealized Gain on Forward Commitments	11,697	9,592	(a) (d)
Other	44	341	(a) (d)
Total FERC Account 254 Regulatory Liabilities	$ 14,530	$ 13,458	
Deferred Investment Tax Credits (c)	$ 2,519	$ 3,395	(a) (f)

(a) Amount does not earn a return.
(b) A portion of this amount effectively earns a return.
(c) Recorded in an account other than regulatory asset or liability on the balance sheet.
(d) Recovery/refund period – various periods.
(e) Recovery/refund period – up to 24 years.
(f) Recovery/refund period – up to 11 years.
(g) Recovery/refund period – up to 1 year.

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 adverse effect on the financial statements.

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an integrated electric utility, subject to various deductibles. The insurance includes coverage for 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 a South Carolina domiciled insurance company, EIS, together with and/or in addition to various industry mutual and 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 have a material adverse effect on net income, cash flows and financial condition.

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. Budgeted construction expenditures for 2009 are $61.9 million. Budgeted 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.

KPCo 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. Management does not expect to incur penalty payments under these provisions that would materially affect net income, cash flows or financial condition.

The following table summarizes KPCo's actual contractual commitments at December 31, 2008:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 164.4	$ 218.7	$ 58.8	$ -	$ 441.9
Energy and Capacity Purchase Contracts (b)	0.6	1.8	0.3	-	2.7
Construction Contracts for Capital Assets (c)	0.3	5.3	9.3	-	14.9
Total	$ 165.3	$ 225.8	$ 68.4	$ -	$ 459.5

(a) Represents contractual commitments to purchase coal, natural gas and other consumables as fuel for electric generation along with related transportation of the fuel. The longest contract extends to the year 2012. The contracts provide for periodic price adjustments and contain various clauses that would release KPCo from its commitments under certain conditions.
(b) Represents contractual commitments for energy and capacity purchase contracts.
(c) Represents only capital assets that are contractual commitments.

GUARANTEES

There is no collateral held in relation to any guarantees. In the event any guarantee is drawn, there is no recourse to third parties.

Indemnifications and Other Guarantees

<u>Contracts</u>

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. There are no material liabilities recorded for any indemnifications.

KPCo, along with the other AEP East companies, PSO and SWEPCo, are jointly and severally liable for activity conducted by AEPSC on behalf of the AEP East companies, PSO and SWEPCo related to purchase power and sale activity conducted pursuant to the SIA.

<u>Lease Obligations</u>

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

CONTINGENCIES

Environmental Settlement

In 1999, the Federal EPA, a number of states and certain special interest groups filed complaints alleging that certain of KPCo's affiliates including APCo, CSPCo, I&M and OPCo modified units at certain of their coal-fired generating plants in violation of the New Source Review (NSR) requirements of the CAA.

As part of a global consent decree covering all coal-fired units in the five eastern states of the AEP System to resolve all past NSR allegations and secure a covenant not to sue for future claims from the Federal EPA, KPCo agreed to complete previously announced flue gas desulfurization emissions control equipment (scrubbers) on Unit 2 of the Big Sandy Plant by December 2015. The obligation to pay a $15 million civil penalty and provide $36 million for environmental mitigation projects coordinated with the federal government and $24 million to the states for environmental mitigation was shared by members of the AEP Power Pool. Under the consent decree, KPCo recorded its share of the costs of $5.2 million in Operation Expenses and Penalties during the third quarter of 2007.

Management believes KPCo can recover any capital and operating costs of additional pollution control equipment that may be required as a result of the consent decree through regulated rates or market prices of electricity. If KPCo is unable to recover such costs, it would adversely affect KPCo's future net income, cash flows and possibly financial condition.

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in federal district court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming, and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The dismissal of the lawsuit was appealed to the Second Circuit Court of Appeals. Briefing and oral argument concluded in 2006. In April 2007, the U.S. Supreme Court issued a decision holding that the Federal EPA has authority to regulate emissions of CO_2 and other greenhouse gases under the CAA, which may impact the Second Circuit's analysis of these issues. The Second Circuit requested supplemental briefs addressing the impact of the Supreme Court's decision on this case which were provided in 2007. Management believes the actions are without merit and intends to defend against the claims.

Alaskan Villages' Claims

In February 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in federal court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil & gas companies, a coal company, and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. The defendants filed motions to dismiss the action. The motions are pending before the court. Management believes the action is without merit and intends to defend against the claims.

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 (PCBs) and other hazardous and nonhazardous materials. KPCo currently incurs costs to safely dispose of these substances.

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. At December 31, 2008, 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 Superfund site separately, but several general statements can be made regarding potential future liability. Disposal of materials at a particular site is often unsubstantiated and the quantity of materials deposited at a site was 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.

FERC Long-term Contracts

In 2002, the FERC held a hearing related to a complaint filed by Nevada Power Company and Sierra Pacific Power Company (the Nevada utilities). The complaint sought to break long-term contracts entered during the 2000 and 2001 California energy price spike which the customers alleged were "high-priced." The complaint alleged that KPCo and certain other AEP subsidiaries sold power at unjust and unreasonable prices because the market for power was allegedly dysfunctional at the time such contracts were executed. In 2003, the FERC rejected the complaint. In 2006, the U.S. Court of Appeals for the Ninth Circuit reversed the FERC order and remanded the case to the FERC for further proceedings. That decision was appealed to the U.S. Supreme Court. In June 2008, the U.S. Supreme Court affirmed the validity of contractually-agreed rates except in cases of serious harm to the public. The U.S. Supreme Court affirmed the Ninth Circuit's remand on two issues, market manipulation and excessive burden on consumers. The FERC initiated remand procedures and gave the parties time to attempt to settle the issues. Management believes a provision recorded in 2008 should be sufficient. Management asserted claims against certain companies that sold power to KPCo and certain other AEP subsidiaries, which was resold to the Nevada utilities, seeking to recover a portion of any amounts that may be owed to the Nevada utilities. Management is unable to predict the ultimate outcome of these proceedings or their impact on future net income and cash flows.

6. BENEFIT PLANS

KPCo participates in AEP sponsored qualified pension plans (merged at December 31, 2008) and unfunded nonqualified pension plans. A substantial majority of employees are covered by either one qualified plan or both a qualified and a nonqualified pension plan. KPCo participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

KPCo recognizes the obligations associated with defined benefit pension plans and OPEB plans in its balance sheets. 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 SFAS 71 regulatory asset for qualifying SFAS 158 costs of regulated operations that for ratemaking purposes are deferred for future recovery.

SFAS 158 requires adjustment of pretax AOCI at the end of each year, for both underfunded and overfunded defined benefit pension and OPEB plans, to an amount 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 and deferred gains result in an AOCI equity addition. The year-end AOCI measure can be volatile based on fluctuating market conditions, investment returns and discount rates.

The following tables provide a reconciliation of the changes in projected benefit obligations and fair value of assets for AEP's plans over the two-year period ending at the plan's measurement date of December 31, 2008, and their funded status as of December 31 for each year:

Projected Plan Obligations, Plan Assets, Funded Status as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	**2007**	**2008**	**2007**
	(in millions)			
Change in Projected Benefit Obligation				
Projected Obligation at January 1	$ 4,109	$ 4,108	$ 1,773	$ 1,818
Service Cost	100	96	42	42
Interest Cost	249	235	113	104
Actuarial Loss (Gain)	139	(64)	2	(91)
Plan Amendments	-	18	-	-
Benefit Payments	(296)	(284)	(120)	(130)
Participant Contributions	-	-	24	22
Medicare Subsidy	-	-	9	8
Projected Obligation at December 31	$ 4,301	$ 4,109	$ 1,843	$ 1,773
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 4,504	$ 4,346	$ 1,400	$ 1,302
Actual Gain (Loss) on Plan Assets	(1,054)	435	(368)	115
Company Contributions	7	7	82	91
Participant Contributions	-	-	24	22
Benefit Payments	(296)	(284)	(120)	(130)
Fair Value of Plan Assets at December 31	$ 3,161	$ 4,504	$ 1,018	$ 1,400
Funded (Underfunded) Status at December 31	$ (1,140)	$ 395	$ (825)	$ (373)

AEP has significant investments in several trust funds to provide for future pension and OPEB payments. All of the trust funds' investments are diversified and managed in compliance with all laws and regulations. The value of the investments in these trusts declined substantially in 2008 due to decreases in domestic and international equity markets. Although the asset values are lower, this decline has not affected the funds' ability to make their required payments.

Amounts Recognized on AEP's Balance Sheets as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	**2007**	**2008**	**2007**
	(in millions)			
Employee Benefits and Pension Assets – Prepaid Benefit Costs	$ -	$ 482	$ -	$ -
Other Current Liabilities – Accrued Short-term Benefit Liability	(9)	(8)	(4)	(4)
Employee Benefits and Pension Obligations – Accrued Long-term Benefit Liability	(1,131)	(79)	(821)	(369)
Funded (Underfunded) Status	$ (1,140)	$ 395	$ (825)	$ (373)

SFAS 158 Amounts Recognized in AEP's Accumulated Other Comprehensive Income (AOCI) as of December 31, 2008 and 2007

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
Components	(in millions)			
Net Actuarial Loss	$ 2,024	$ 534	$ 715	$ 231
Prior Service Cost	13	14	3	4
Transition Obligation	-	-	70	97
Pretax AOCI	$ 2,037	$ 548	$ 788	$ 332
Recorded as				
Regulatory Assets	$ 1,660	$ 453	$ 502	$ 204
Deferred Income Taxes	132	33	100	45
Net of Tax AOCI	245	62	186	83
Pretax AOCI	$ 2,037	$ 548	$ 788	$ 332

Components of the Change in AEP's Plan Assets and Benefit Obligations Recognized in Pretax AOCI during the years ended December 31, 2008 and 2007 are as follows:

	Pensions Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
Components	(in millions)			
Actuarial Loss (Gain) During the Year	$ 1,527	$ (166)	$ 492	$ (111)
Amortization of Actuarial Loss	(37)	(59)	(9)	(12)
Prior Service Cost (Credit)	(1)	19	-	-
Amortization of Transition Obligation	-	-	(27)	(27)
Total Pretax AOCI Change for the Year	$ 1,489	$ (206)	$ 456	$ (150)

Pension and Other Postretirement Plans' Assets

The asset allocations for AEP's pension plans at the end of 2008 and 2007, and the target allocation for 2009, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2009	2008	2007
Asset Category			
Equity Securities	55%	47%	57%
Real Estate	5%	6%	6%
Debt Securities	39%	42%	36%
Cash and Cash Equivalents	1%	5%	1%
Total	100%	100%	100%

The asset allocations for AEP's OPEB plans at the end of 2008 and 2007, and target allocation for 2009, by asset category, are as follows:

	Target Allocation	Percentage of Plan Assets at Year End	
	2009	2008	2007
Asset Category			
Equity Securities	65%	53%	62%
Debt Securities	34%	43%	35%
Cash and Cash Equivalents	1%	4%	3%
Total	100%	100%	100%

AEP's investment strategy for the employee benefit 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 plans' assets relative to the plans' liabilities. To minimize investment risk, AEP's employee benefit trust funds are broadly diversified among classes of assets, investment strategies and investment managers. AEP regularly reviews the actual asset allocation and periodically rebalances the investments to AEP's targeted allocation when considered appropriate. AEP's 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. AEP's investment policies prohibit the benefit trust funds from purchasing AEP securities (with the exception of proportionate and immaterial holdings of AEP securities in passive index strategies). However, AEP's 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, including the Employee Retirement Income Security Act (ERISA).

The value of the pension plans' assets decreased substantially to $3.2 billion at December 31, 2008 from $4.5 billion at December 31, 2007. The qualified plans paid $289 million in benefits to plan participants during 2008 (nonqualified plans paid $7 million in benefits). The value of AEP's OPEB plans' assets decreased substantially to $1 billion at December 31, 2008 from $1.4 billion at December 31, 2007. The OPEB plans paid $120 million in benefits to plan participants during 2008.

AEP bases the 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.

	December 31,	
	2008	2007
Accumulated Benefit Obligation	(in millions)	
Qualified Pension Plans	$ 4,119	$ 3,914
Nonqualified Pension Plans	80	77
Total	$ 4,199	$ 3,991

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 at December 31, 2008 and 2007 were as follows:

	Underfunded Pension Plans			
	December 31,			
	2008		2007	
	(in millions)			
Projected Benefit Obligation	$	4,301	$	81
Accumulated Benefit Obligation	$	4,199	$	77
Fair Value of Plan Assets		3,161		-
Underfunded Accumulated Benefit Obligation	$	1,038	$	77

Actuarial Assumptions for Benefit Obligations

The weighted-average assumptions as of December 31, used in the measurement of AEP's benefit obligations are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2008**	**2007**	**2008**	**2007**
Discount Rate	6.00%	6.00%	6.10%	6.20%
Rate of Compensation Increase	5.90% (a)	5.90% (a)	N/A	N/A

(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.

N/A = Not Applicable

To determine a discount rate, AEP uses a duration-based method by constructing a hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2008, the rate of compensation increase assumed varies with the age of the employee, ranging from 5% per year to 11.5% per year, with an average increase of 5.9%.

Estimated Future Benefit Payments and Contributions

Information about the 2009 expected cash flows for the pension (qualified and nonqualified) and OPEB plans is as follows:

Employer Contributions	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Required Contributions (a)	$ 9	$ 4
Additional Discretionary Contributions	-	158

(a) Contribution required to meet minimum funding requirement under ERISA plus direct payments for unfunded benefits.

The contribution to the pension plans is based on the minimum amount required by ERISA plus the amount to pay unfunded nonqualified benefits. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit cost for accounting purposes as provided for in agreements with state regulatory authorities, plus the additional discretionary contribution of AEP's Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from the employer's assets, including both the employer's share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. 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 AEP's pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2009	$ 378	$ 116	$ (10)
2010	379	126	(11)
2011	377	136	(12)
2012	378	143	(13)
2013	384	151	(14)
Years 2014 to 2018, in Total	1,920	876	(87)

Components of Net Periodic Benefit Cost

The following table provides the components of AEP's net periodic benefit cost for the plans for the years ended December 31, 2008 and 2007:

	Pensions Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2008	2007	2008	2007
	(in millions)			
Service Cost	$ 100	$ 96	$ 42	$ 42
Interest Cost	249	235	113	104
Expected Return on Plan Assets	(336)	(340)	(111)	(104)
Amortization of Transition Obligation	-	-	27	27
Amortization of Prior Service Cost	1	-	-	-
Amortization of Net Actuarial Loss	37	59	9	12
Net Periodic Benefit Cost	51	50	80	81
Capitalized Portion	(16)	(14)	(25)	(25)
Net Periodic Benefit Cost Recognized as Expense	$ 35	$ 36	$ 55	$ 56

Estimated amounts expected to be amortized to net periodic benefit costs for AEP's plans during 2009 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 56	$ 46
Prior Service Cost	1	1
Transition Obligation	-	27
Total Estimated 2009 Pretax AOCI Amortization	$ 57	$ 74
Expected to be Recorded as		
Regulatory Asset	$ 46	$ 48
Deferred Income Taxes	4	9
Net of Tax AOCI	7	17
Total	$ 57	$ 74

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

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2008	2007	2008	2007
	(in thousands)			
Benefit Costs	$ 995	$ 1,018	$ 1,618	$ 1,706

Actuarial Assumptions for Net Periodic Benefit Costs

The weighted-average assumptions as of January 1, used in the measurement of AEP's benefit costs are shown in the following tables:

	Pension Plans		Other Postretirement Benefit Plans	
	2008	2007	2008	2007
Discount Rate	6.00%	5.75%	6.20%	5.85%
Expected Return on Plan Assets	8.00%	8.50%	8.00%	8.00%
Rate of Compensation Increase	5.90%	5.90%	N/A	N/A

N/A = Not Applicable

The expected return on plan assets for 2008 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, used for OPEB plans measurement purposes are shown below:

Health Care Trend Rates	2008	2007
Initial	7.0%	7.5%
Ultimate	5.0%	5.0%
Year Ultimate Reached	2012	2012

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	$ 20	$ (16)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	196	(163)

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 company matching contributions. The matching contributions to the plan was 75% of the first 6% of eligible compensation contributed by the employee in 2008. Effective January 1, 2009, the match is 100% of the first 1% of eligible employee contributions and 70% of the next 5% of contributions. The cost for contributions to the plan totaled $1.6 million in 2008 and $1.4 million in 2007.

7. BUSINESS SEGMENTS

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

8. DERIVATIVES, HEDGING AND FAIR VALUE MEASUREMENTS

DERIVATIVES AND HEDGING

SFAS 133 requires recognition of all qualifying derivative instruments as either assets or liabilities in the statement of financial position 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 and supply and demand market data and assumptions. The fair values determined are reduced by the appropriate valuation adjustments for items such as discounting, liquidity and credit quality. Credit risk is the risk that the counterparty to the contract will fail to perform or fail to pay amounts due. Liquidity risk represents the risk that imperfections in the market will cause the price to be less than or more than what the price should be based purely on supply and demand. 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 can and will cause reasonable price curves to differ from actual prices throughout a contract's term and at the time a contract settles. Therefore, there could be significant adverse or favorable effects on future net income and cash flows if market prices are not consistent with management's approach at estimating current market consensus for forward prices in the current period. This is particularly true for long-term contracts.

Certain qualifying derivative instruments have been designated as normal purchases or normal sales contracts, as provided in SFAS 133. Derivative contracts that have been designated as normal purchases or normal sales under SFAS 133 are not subject to MTM accounting treatment and are recognized in the income statements 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, KPCo designates a hedging instrument as a fair value hedge or cash flow hedge. For fair value hedges (i.e. hedging the exposure to changes in the fair value of an asset, liability or an identified portion thereof that is attributable to a particular risk), KPCo recognizes the gain or loss on the derivative instrument as well as the offsetting loss or gain on the hedged item associated with the hedged risk in net income during the period of change. 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) until the period the hedged item affects net income. KPCo records hedge ineffectiveness as a regulatory asset (for losses) or a regulatory liability (for gains).

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. Realized gains and losses on derivative instruments held for trading purposes are included in Operating Revenues where the AEP System owns assets or in adjacent markets. The realized gains and losses for certain legacy transactions executed outside of the AEP System are reported as Miscellaneous Nonoperating Income. Realized gains and losses on derivative instruments not held for trading purposes are included in revenues or expenses depending on the relevant facts and circumstances. KPCo's unrealized gains and losses for both trading and non-trading derivative instruments are recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Fair Value Hedging Strategies

At certain times, KPCo enters into interest rate derivative transactions in order to manage existing fixed interest rate risk exposure. These interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of fixed-rate debt to a floating rate. KPCo records gains or losses on swaps that qualify for fair value hedge accounting treatment, as well as offsetting changes in the fair value of the debt being hedged, in Interest Charges. During 2007, KPCo recognized no hedge ineffectiveness related to these derivative transactions.

Cash Flow Hedging Strategies

KPCo enters into, and designates as cash flow hedges, certain derivative transactions for the purchase and sale of electricity and natural gas in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. Management closely monitors the potential impacts of commodity price changes, and where appropriate, enters into derivative transactions to protect margins for a portion of future electricity sales and fuel purchases. Realized gains and losses on these derivatives designated as cash flow hedges are included in Operating Revenues or Operation Expenses, depending on the specific nature of the risk being hedged. KPCo does not hedge all variable price risk exposure related to energy commodities. At various times during 2008 and 2007, KPCo designated cash flow hedge relationships using these commodities and recognized immaterial amounts related to hedge ineffectiveness. However, there was no earnings impact because KPCo operates in a regulated jurisdiction.

KPCo enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. KPCo enters into various derivative instruments to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. The anticipated debt offerings have a high probability of occurrence because the proceeds will be used to fund existing debt maturities as well as fund projected capital expenditures. KPCo reclassifies gains and losses on the hedges from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which the interest payments being hedged occur. At various times during 2007, KPCo designated interest rate derivatives as cash flow hedges and recognized immaterial amounts related to hedge ineffectiveness. However, there was no earnings impact because KPCo operates in a regulated jurisdiction.

KPCo approximates net gains of $502 thousand from cash flow hedges in Accumulated Other Comprehensive Income (Loss) at December 31, 2008 that are expected to be reclassified to net income in the next twelve months as the items being hedged settle. In addition, the maximum length of time that the variability of future cash flows is being hedged is 24 months. The actual amounts reclassified from AOCI to Net Income can differ as a result of market price changes.

Credit Risk

Credit risk is the risk of financial loss if counterparties fail to perform their contractual obligations. KPCo limits its credit risk by maintaining stringent credit policies whereby KPCo assesses a counterparty's creditworthiness prior to transacting with them and continue to assess their creditworthiness on an ongoing basis. KPCo employees the use of 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 is exceeded in excess of an 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 also provide that the failure or inability to post collateral is sufficient cause for termination and liquidation of all positions.

FAIR VALUE MEASUREMENTS

SFAS 107 Fair Value Measurements

The fair values of Long-term Debt are based on quoted market prices for the same or similar issues and the current interest rates offered for instruments with similar maturities. 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 for KPCo at December 31, 2008 and 2007 are summarized in the following table:

	December 31,			
	2008		2007	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 418,555	$ 366,108	$ 448,373	$ 442,090

SFAS 157 Fair Value Measurements

As described in Note 2, KPCo completed the adoption of SFAS 157 effective January 1, 2009. The statement defines fair value, establishes a fair value measurement framework and expands fair value disclosures. The adoption of SFAS 157 had an immaterial impact on the financial statements. The provisions of SFAS 157 are applied prospectively, except for a) changes in fair value measurements of existing derivative financial instruments measured initially using the transaction price under EITF Issue No. 02-3 "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities" (EITF 02-3), b) existing hybrid financial instruments measured initially at fair value using the transaction price and c) blockage discount factors. Although the statement is applied prospectively upon adoption, in accordance with the provisions of SFAS 157 related to EITF 02-3, amounts for transition adjustment are recorded to beginning retained earnings. The impact of considering AEP's own credit risk when measuring the fair value of liabilities, including derivatives, had an immaterial impact on KPCo's fair value measurements upon adoption.

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

As defined in SFAS 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). SFAS 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement).

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

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

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

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

The following table sets forth by level within the fair value hierarchy KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

Assets and Liabilities Measured at Fair Value on a Recurring Basis as of December 31, 2008

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Derivative Instrument Assets:					
Risk Management Contracts (a)	$ 3,443	$ 140,387	$ 2,561	$ (125,636)	$ 20,755
Dedesignated Risk Management Contracts (b)	-	-	-	2,749	2,749
Total Derivative Instrument Assets	3,443	140,387	2,561	(122,887)	23,504
Derivative Instrument Assets – Hedges (a) (c)	-	1,418	-	(302)	1,116
Total Assets	$ 3,443	$ 141,805	$ 2,561	$ (123,189)	$ 24,620
Liabilities:					
Derivative Instrument Liabilities:					
Risk Management Contracts (a)	$ 4,021	$ 132,087	$ 848	$ (126,370)	$ 10,586
DETM Assignment (c)	-	-	-	1,118	1,118
Total Derivative Instrument Liabilities	4,021	132,087	848	(125,252)	11,704
Derivative Instrument Liabilities – Hedges (a)	-	544	-	(302)	242
Total Liabilities	$ 4,021	$ 132,631	$ 848	$ (125,554)	$ 11,946

(a) Amounts in "Other" column primarily represent counterparty netting of risk management contracts and associated cash collateral under FSP FIN 39-1.

(b) "Dedesignated Risk Management Contracts" are contracts that were originally MTM but were subsequently elected as normal under SFAS 133. At the time of the normal election, the MTM value was frozen and no longer fair valued. This will be amortized into revenues over the remaining life of the contract.

(c) See "Natural Gas Contracts with DETM" section of Note 12.

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

	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of January 1, 2008	$ (157)
Realized (Gain) Loss Included in Net Income (or Changes in Net Assets) (a)	95
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	-
Transfers in and/or out of Level 3 (b)	(192)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	1,967
Balance as of December 31, 2008	$ 1,713

(a) Included in revenues on the statements of income.
(b) "Transfers in and/or out of Level 3" represent existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as level 3 for which the lowest significant input became observable during the period.
(c) "Changes in Fair Value Allocated to Regulated Jurisdictions" relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory assets/liabilities.

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2008	Years Ended December 31, 2007
	(in thousands)	
Charged (Credited) to Operating Expenses, Net:		
Current	$ 5,190	$ 12,888
Deferred	5,031	5,434
Deferred Investment Tax Credits	(875)	(1,007)
Total	9,346	17,315
Charged (Credited) to Nonoperating Income, Net:		
Current	(516)	(1,630)
Deferred	(934)	257
Deferred Investment Tax Credits	-	45
Total	(1,450)	(1,328)
Total Income Tax	$ 7,896	$ 15,987

Shown below is a reconciliation of the difference between the amount of federal income taxes computed by multiplying book income before income taxes by the federal statutory rate and the amount of income taxes reported.

	Years Ended December 31, 2008	2007
	(in thousands)	
Net Income	$ 24,531	$ 32,470
Income Taxes	7,896	15,987
Pretax Income	$ 32,427	$ 48,457
Income Tax on Pretax Income at Statutory Rate (35%)	$ 11,349	$ 16,960
Increase (Decrease) in Income Tax resulting from the following items:		
Depreciation	1,169	1,223
Allowance for Funds Used During Construction	(872)	(661)
Removal Costs	(4,110)	(1,766)
Investment Tax Credits, Net	(875)	(962)
State and Local Income Taxes	1,072	736
Other	163	457
Total Income Taxes	$ 7,896	$ 15,987
Effective Income Tax Rate	24.4%	33.0%

The following table shows the elements of the net deferred tax liability and the significant temporary differences:

	December 31, 2008	2007
	(in thousands)	
Deferred Tax Assets	$ 56,519	$ 35,037
Deferred Tax Liabilities	(314,623)	(281,962)
Net Deferred Tax Liabilities	$ (258,104)	$ (246,925)
Property Related Temporary Differences	$ (205,880)	$ (189,190)
Amounts Due From Customers For Future Federal Income Taxes	(27,299)	(25,794)
Deferred State Income Taxes	(29,955)	(27,643)
Deferred Income Taxes on Other Comprehensive Loss	(32)	438
Deferred Fuel and Purchased Power	54	(1,617)
Accrued Pensions	8,959	(3,521)
All Other, Net	(3,951)	402
Net Deferred Tax Liabilities	$ (258,104)	$ (246,925)

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

KPCo and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2000. KPCo and other AEP subsidiaries have completed the exam for the years 2001 through 2003 and have issues that are being pursued at the appeals level. The returns for the years 2004 through 2006 are presently under audit by the IRS. Although the outcome of tax audits is uncertain, in management's opinion, adequate provisions for income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to have a material adverse effect on net income.

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

Prior to the adoption of FIN 48, KPCo recorded interest and penalty expense related to uncertain tax positions in tax expense accounts. With the adoption of FIN 48 on January 1, 2007, KPCo began recognizing interest accruals related to uncertain tax positions in interest income or expense as applicable, and penalties in Penalties. The impact of this interpretation was an unfavorable adjustment to the 2007 opening balance of retained earnings of $786 thousand. In 2008, KPCo reported $303 thousand of interest expense and $1.9 million of interest income. In 2007, KPCo reported $55 thousand of interest expense and reversed $926 thousand of prior period interest expense. KPCo had approximately $1.7 million for the receipt of interest accrued at December 31, 2008 and $788 thousand and $1.3 million for the payment of interest and penalties accrued at December 31, 2008 and 2007, respectively.

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

	2008	2007
	(in thousands)	
Balance at January 1,	$ 2,205	$ 3,413
Increase - Tax Positions Taken During a Prior Period	-	1
Decrease - Tax Positions Taken During a Prior Period	(113)	(1,796)
Increase - Tax Positions Taken During the Current Year	1,301	587
Decrease - Tax Positions Taken During the Current Year	(144)	-
Increase - Settlements with Taxing Authorities	96	-
Decrease - Lapse of the Applicable Statute of Limitations	-	-
Balance at December 31,	$ 3,345	$ 2,205

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $881 thousand and $936 thousand in 2008 and 2007, respectively. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

Several tax bills and other legislation with tax-related sections were enacted in 2007, including the Tax Technical Corrections Act of 2007, the Tax Increase Prevention Act of 2007 and the Energy Independence and Security Act of 2007. The tax law changes enacted in 2007 did not materially affect net income, cash flows or financial condition.

The Economic Stimulus Act of 2008 was signed into law by the President in February 2008. It provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a material favorable cash flow benefit of approximately $8 million.

In October 2008, the Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law. The 2008 Act extended several expiring tax provisions and added new energy incentive provisions. The legislation impacted the availability of research credits, accelerated depreciation of smart meters, production tax credits, and energy efficient commercial building deductions. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income, cash flows or financial condition.

In February 2009, the American Recovery and Reinvestment Tax Act of 2009 (the 2009 Act) was signed into law. The 2009 Act extended the bonus depreciation deduction for one year and provides for a long-term extension of the renewable production tax credit for wind energy and other properties. The 2009 Act also establishes a new investment tax credit for the manufacture of advanced energy property as well as appropriations for advanced energy research projects, carbon capture and storage and gridSMART technology. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income or financial condition, but is expected to have a positive material impact on cash flows.

State Tax Legislation

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

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

In March 2008, the Governor of West Virginia signed legislation providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. Management has evaluated the impact of the law change and the application of the law change will not materially impact net income, cash flows or financial condition.

10. LEASES

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

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

Lease Rental Costs	Years Ended December 31, 2008 (in thousands)	2007
Net Lease Expense on Operating Leases	$ 2,250	$ 2,405
Amortization of Capital Leases	971	1,141
Interest on Capital Leases	102	140
Total Lease Rental Costs	$ 3,323	$ 3,686

The following table shows Utility Plant under capital leases and related obligations recorded on the balance sheets.

Property, Plant and Equipment Under Capital Leases	December 31, 2008 (in thousands)	2007
Production	$ -	$ 22
Other	3,974	5,261
Total Property, Plant and Equipment Under Capital Leases	3,974	5,283
Accumulated Amortization	2,152	3,039
Net Property, Plant and Equipment Under Capital Leases	$ 1,822	$ 2,244
Obligations Under Capital Leases		
Noncurrent	$ 1,045	$ 1,272
Current	777	972
Total Obligations Under Capital Leases	$ 1,822	$ 2,244

Future minimum lease payments consisted of the following at December 31, 2008:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2009	$ 804	$ 2,032
2010	588	1,803
2011	446	7,451
2012	15	98
2013	15	98
Later Years	18	432
Total Future Minimum Lease Payments	$ 1,886	$ 11,914
Less Estimated Interest Element	64	
Estimated Present Value of Future Minimum Lease Payments	$ 1,822	

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. GE Capital Commercial Inc. (GE) notified management in November 2008 that they elected to terminate the Master Leasing Agreements in accordance with the termination rights specified within the contract. In 2011, KPCo will be required to purchase all equipment under the lease and pay GE an amount equal to the unamortized value of all equipment then leased. As a result, the unamortized value of this equipment of $6 million is reflected in KPCo's future minimum lease payments for 2011. In December 2008, management signed new master lease agreements with one-year commitment periods that include lease terms of up to 10 years. Management expects to enter into replacement leasing arrangements for the equipment affected by this notification prior to the termination date of 2011.

For equipment under the GE master lease agreements that expire prior to 2011, the lessor is guaranteed receipt of up to 87% of the unamortized balance of the equipment at the end of the lease term. If the fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the fair market value and the unamortized balance, with the total guarantee not to exceed 87% of the unamortized balance. Under the new master lease agreements, the lessor is guaranteed receipt of up to 68% of the unamortized balance at the end of the lease term. If the actual fair market value of the leased equipment is below the unamortized balance at the end of the lease term, KPCo is committed to pay the difference between the actual fair market value and unamortized balance, with the total guarantee not to exceed 68% of the unamortized balance. At December 31, 2008, the maximum potential loss for these lease agreements was approximately $613 thousand assuming the fair market value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair market value has been in excess of the unamortized balance.

11. FINANCING ACTIVITIES

Long-term Debt

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

The following details long-term debt outstanding as of December 31, 2008 and 2007:

Type of Debt	Maturity	Weighted Average Interest Rate at December 31, 2008	Interest Rate Ranges at December 31, 2008	2007	Outstanding at December 31, 2008	2007
					(in thousands)	
Senior Unsecured Notes	2008-2032	5.93%	5.625%-6.00%	5.625%-6.45%	$ 400,000	$ 430,000
Notes Payable – Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Unamortized Discount					(1,445)	(1,627)
Total Long-term Debt					$ 418,555	$ 448,373

At December 31, 2008, all future annual long-term debt payments are due after December 31, 2013.

Utility Money Pool – AEP System

The AEP System uses a corporate borrowing program to meet the short-term borrowing needs of its subsidiaries. The corporate borrowing program includes a Utility Money Pool, which funds the utility subsidiaries. The AEP System corporate borrowing program operates in accordance with the terms and conditions approved in a regulatory order. The amount of outstanding borrowings from the Utility Money Pool as of December 31, 2008 and 2007 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, 2008 and 2007 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Borrowings from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
	(in thousands)					
2008	$ 142,416	$ -	$ 54,536	$ -	$ 131,399	$ 250,000
2007	164,913	181,970	59,104	115,727	19,153	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, 2008 and 2007 are summarized in the following table:

Years Ended December 31,	Maximum Interest Rates for Funds Borrowed from the Utility Money Pool	Minimum Interest Rates for Funds Borrowed from the Utility Money Pool	Maximum Interest Rates for Funds Loaned to the Utility Money Pool	Minimum Interest Rates for Funds Loaned to the Utility Money Pool	Average Interest Rates for Funds Borrowed from the Utility Money Pool	Average Interest Rates for Funds Loaned to the Utility Money Pool
2008	5.47%	2.28%	-%	-%	3.42%	-%
2007	5.92%	5.29%	5.94%	5.16%	5.50%	5.58%

Interest expense and interest income related to the Utility Money Pool are included in Interest Charges and Interest and Dividend Income, respectively. 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, 2008 and 2007:

	Years Ended December 31,	
	2008	2007
	(in thousands)	
Interest Expense	$ 1,893	$ 2,494
Interest Income	-	1,614

Dividend Restrictions

Under the Federal Power Act, KPCo is restricted from paying dividends out of stated capital.

Credit Facilities

In April 2008, KPCo and certain other companies in the AEP System entered into a $650 million 3-year credit agreement and a $350 million 364-day credit agreement which were reduced by Lehman Brothers Holdings Inc.'s commitment amount of $23 million and $12 million, respectively, following its bankruptcy. Under the facilities, letters of credit may be issued. As of December 31, 2008, there were no outstanding amounts for KPCo under either facility.

Sale of Receivables – AEP Credit

AEP Credit has a sale of receivables agreement with banks and commercial paper conduits. Under the sale of receivables agreement, AEP Credit sells an interest in the receivables it acquires from affiliated utility subsidiaries to the commercial paper conduits and banks and receives cash.

In October 2008, AEP renewed AEP Credit's sale of receivables agreement. The sale of receivables agreement provides a commitment of $700 million from banks and commercial paper conduits to purchase receivables from AEP Credit. This agreement will expire in October 2009. AEP intends to extend or replace the sale of receivables agreement.

AEP Credit purchases accounts receivable through a purchase agreement with KPCo. Under the factoring 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 financing costs, KPCo's uncollectible accounts experience and administrative costs.

KPCo's factored accounts receivable and accrued unbilled revenues were $55.8 million and $41.4 million as of December 31, 2008 and 2007, respectively.

KPCo paid fees to AEP Credit for factoring customer accounts receivable of $3.2 million and $3.8 million for the years ended December 31, 2008 and 2007, respectively. The costs of factoring customer accounts receivable are reported in Other Deductions.

12. RELATED PARTY TRANSACTIONS

For other related party transactions, also see "Utility Money Pool – AEP System" and "Sale of Receivables – AEP Credit" sections of Note 11.

AEP Power Pool

APCo, CSPCo, I&M, KPCo and OPCo are parties to the Interconnection Agreement, dated July 6, 1951, as amended (the Interconnection Agreement), defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's member load ratio, which is calculated monthly on the basis of each company's maximum peak demand in relation to the sum of the maximum peak demands of all five companies during the preceding 12 months. In addition, since 1995, APCo, CSPCo, I&M, KPCo and OPCo have been parties to the AEP System Interim Allowance Agreement, which provides, among other things, for the transfer of SO_2 allowances associated with the transactions under the Interconnection Agreement.

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

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). It is designed to function as an umbrella agreement in addition to the Interconnection Agreement and the CSW Operating Agreement, each of which controls the distribution of costs and benefits within a zone.

In November 2005, AEP filed with the FERC a proposed amendment to the SIA to change the method of allocating profits from off-system electricity sales between the East and West zones. The proposed method causes such profits to be allocated generally on the basis of the zone in which the underlying transactions occur or originate. The filing was made in accordance with a provision of the agreement that called for a re-evaluation of the allocation method effective January 1, 2006 and was approved as filed effective April 1, 2006.

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

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

Affiliated Revenues and Purchases

The following table shows the revenues derived from sales to the pools, direct sales to affiliates, natural gas contracts with AEPES, and other revenues for the years ended December 31, 2008 and 2007:

Related Party Revenues	Years Ended December 31, 2008	2007
	(in thousands)	
Sales to AEP Power Pool	$ 62,642	$ 56,708
Direct Sales to West Affiliates	3,521	3,738
Natural Gas Contracts with AEPES	(133)	(197)
Other	219	302

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2008 and 2007:

Related Party Purchases	Years Ended December 31, 2008	2007
	(in thousands)	
Purchases from AEP Power Pool	$ 127,669	$ 96,997
Direct Purchases from East Affiliates	106,256	88,051
Direct Purchases from West Affiliates	454	351

AEP System Transmission Pool

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 Equalization Agreement (TEA) and the Transmission Coordination Agreement (TCA). The System Transmission Integration Agreement contains two service schedules that govern:

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

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

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TEA, dated April 1, 1984, as amended, defining how they share the costs associated with their relative ownership of the extra-high-voltage transmission system (facilities rated 345 kV and above) and certain facilities operated at lower voltages (138 kV and above). Like the Interconnection Agreement, this sharing is based upon each company's member load ratio.

KPCo's net credits as allocated under the TEA during the years ended December 31, 2008 and 2007 were $2 million and $800 thousand, respectively, and were recorded in Operation Expenses.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997. 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 AEP West companies.

Natural Gas Contracts with DETM

Effective October 31, 2003, AEPES assigned to AEPSC, as agent for the AEP East companies, approximately $97 million (negative value) associated with its natural gas contracts with DETM. The assignment was executed in order to consolidate DETM positions within AEP. Beginning in 2007, PSO and SWEPCo were allocated a portion of the DETM assignment based on the SIA methodology of sharing trading and marketing margins between the AEP East companies and PSO and SWEPCo. Concurrently, in order to ensure that there would be no financial impact to the AEP East companies, PSO or SWEPCo as a result of the assignment, AEPES and AEPSC entered into agreements requiring AEPES to reimburse AEPSC for any related cash settlements and all income related to the assigned contracts. KPCo's risk management liabilities related to DETM at December 31, 2008 and 2007 were $1.1 million and $1.9 million, respectively.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with those two parties to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. KPCo's related purchases of gas managed by AEPES were $257 thousand and $930 thousand for the years ended December 31, 2008 and 2007, respectively. These purchases are reflected in Operation Expenses.

Unit Power Agreements (UPA)

A unit power agreement 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. 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 unit power agreement 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 has agreed to pay 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 unit power agreement 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 costs of $9 thousand and $80 thousand in 2008 and 2007, respectively, for urea transloading provided by I&M.

Central Machine Shop

APCo operates a facility which repairs and rebuilds specialized components for the generation plants across the AEP System. APCo defers on its balance sheet the cost of performing the services, then transfers the cost to the affiliate for reimbursement. KPCo recorded these billings as capital or maintenance expense depending on the nature of the services received. These billings are recoverable from customers. KPCo's billed amounts were $1.2 million and $167 thousand for the years ended December 31, 2008 and 2007, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use of affiliate's 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 records these costs or reimbursements as costs or reduction of costs, respectively, in Fuel Stock on its 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,	
	2008	2007
Billing Company	(in thousands)	
APCo	$ 274	$ 90
OPCo	332	183

AEP Power Pool Purchases from OVEC

Beginning in 2006, the AEP Power Pool began purchasing power from OVEC as part of wholesale marketing and risk management activity. The agreement expired in May 2008 and subsequently ended in December 2008. KPCo recorded $4 million and $2 million for the years ended December 31, 2008 and 2007, respectively.

Sales and Purchases of Property

KPCo had affiliated sales and purchases of electric property individually amounting to $100 thousand or more for the years ended December 31, 2008 and 2007 as shown in the following table:

	Years Ended December 31,	
	2008	2007
Companies	(in thousands)	
I&M to KPCo	$ 444	$ -
OPCo to KPCo	-	133

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2008 and 2007 as shown in the following table:

	APCO	CSPCo	I&M	KGPCo	OPCo	PSO	SWEPCo	TCC	WPCo	Total
Sales					(in thousands)					
2008	$ 354	$ 11	$ 16	$ 6	$ 121	$ -	$ 2	$ 33	$ -	$ 543
2007	345	38	21	10	124	85	7	-	66	696
Purchases										
2008	$ 112	$ -	$ 15	$ -	$ 95	$ -	$ -	$ -	$ -	$ 222
2007	518	6	4	1	197	-	-	-	5	731

The amounts above are recorded in Utility Plant. Transfers are performed at cost.

Global Borrowing Notes

AEP issued long-term debt, a portion of which was loaned to KPCo. The debt is reflected in Advances from Associated Companies on the balance sheets. AEP pays the interest on the global notes, but KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accounts Payable to Associated Companies on the balance sheets. KPCo participated in the global borrowing arrangement during 2008 and 2007.

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 bases 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. Billings are capitalized or expensed depending on the nature of the services rendered.

AEPSC

AEPSC provides certain managerial and professional services to KPCo. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo at AEPSC's cost. KPCo has not provided financial or other support outside the reimbursement of costs for services rendered. The cost reimbursement nature of AEPSC finances its operations. There are no other terms or arrangements between AEPSC and KPCo that could require additional financial support from KPCo or expose them to losses outside of the normal course of business. AEPSC and its billings are subject to regulation by the FERC. KPCo is exposed to losses to the extent it cannot recover the costs of AEPSC through its normal business operations. KPCo is considered to have a significant interest in the variability of AEPSC due to its activity in AEPSC's cost reimbursement structure. 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. Total billings from AEPSC for the years ended December 31, 2008 and 2007 were $46.4 million and $35.3 million, respectively.

13. PROPERTY, PLANT AND EQUIPMENT

Depreciation

KPCo provides for depreciation of Utility Plant on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class. The following table provides the annual composite depreciation rates by functional class generally used for the years 2008 and 2007:

Year	Steam	Transmission	Distribution	General
		(in percentages)		
2008	3.5	1.6	3.4	8.1
2007	3.8	1.7	3.4	8.7

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 SFAS 143 "Accounting for Asset Retirement Obligations" and FIN 47 "Accounting for Conditional Asset Retirement Obligations" for the retirement of ash ponds 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 2008 and 2007 aggregate carrying amounts of ARO:

Year	ARO at January 1,	Accretion Expense	Liabilities Incurred	Liabilities Settled	Revisions in Cash Flow Estimates	ARO at December 31,
			(in thousands)			
2008	$ 944	$ 52	$ -	$ (590)	$ 2,869	$ 3,275
2007	1,175	63	-	(294)	-	944

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

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

1. Report in columns (b),(c),(d) and (e) the amounts of accumulated other comprehensive income items, on a net-of-tax basis, where appropriate.

2. Report in columns (f) and (g) the amounts of other categories of other cash flow hedges.

3. For each category of hedges that have been accounted for as "fair value hedges", report the accounts affected and the related amounts in a footnote.

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

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

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	273,381	1,278,779	1,552,160		
2	(51,837)	(1,253,129)	(1,304,966)		
3	(805,619)	(255,123)	(1,060,742)		
4	(857,456)	(1,508,252)	(2,365,708)	32,469,557	30,103,849
5	(584,075)	(229,473)	(813,548)		
6	(584,075)	(229,473)	(813,548)		
7	60,421	260,013	320,434		
8		552,698	552,698		
9	60,421	812,711	873,132	24,531,321	25,404,453
10	(523,654)	583,238	59,584		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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 (f) common function.

Line No.	Classification (a)	Total Company for the Current Year/Quarter Ended (b)	Electric (c)
1	Utility Plant		
2	In Service		
3	Plant in Service (Classified)	1,462,671,719	1,462,671,719
4	Property Under Capital Leases	1,821,930	1,821,930
5	Plant Purchased or Sold		
6	Completed Construction not Classified	81,082,511	81,082,511
7	Experimental Plant Unclassified		
8	Total (3 thru 7)	1,545,576,160	1,545,576,160
9	Leased to Others		
10	Held for Future Use	6,808,947	6,808,947
11	Construction Work in Progress	46,649,955	46,649,955
12	Acquisition Adjustments		
13	Total Utility Plant (8 thru 12)	1,599,035,062	1,599,035,062
14	Accum Prov for Depr, Amort, & Depl	506,112,000	506,112,000
15	Net Utility Plant (13 less 14)	1,092,923,062	1,092,923,062
16	Detail of Accum Prov for Depr, Amort & Depl		
17	In Service:		
18	Depreciation	485,838,475	485,838,475
19	Amort & Depl of Producing Nat Gas Land/Land Right		
20	Amort of Underground Storage Land/Land Rights		
21	Amort of Other Utility Plant	20,273,525	20,273,525
22	Total in Service (18 thru 21)	506,112,000	506,112,000
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)	506,112,000	506,112,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

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

Gas (d)	Other (Specify) (e)	Other (Specify) (f)	Other (Specify) (g)	Common (h)	Line No.
					1
					2
					3
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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	/ /	End of 2008/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	19,305,464	3,338,566
5	TOTAL Intangible Plant (Enter Total of lines 2, 3, and 4)	19,358,383	3,338,566
6	2. PRODUCTION PLANT		
7	A. Steam Production Plant		
8	(310) Land and Land Rights	1,076,546	
9	(311) Structures and Improvements	39,399,282	1,533,583
10	(312) Boiler Plant Equipment	337,539,477	23,004,352
11	(313) Engines and Engine-Driven Generators		
12	(314) Turbogenerator Units	75,031,893	29,686,507
13	(315) Accessory Electric Equipment	15,216,268	103,305
14	(316) Misc. Power Plant Equipment	7,120,767	78,252
15	(317) Asset Retirement Costs for Steam Production	468,403	2,869,019
16	TOTAL Steam Production Plant (Enter Total of lines 8 thru 15)	475,852,636	57,275,018
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)	475,852,636	57,275,018

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

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

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					1
					2
			52,919		3
336,883			22,307,147		4
336,883			22,360,066		5
					6
					7
			1,076,546		8
348,944			40,583,921		9
5,305,939			355,237,890		10
					11
211,543			104,506,857		12
16,287			15,303,286		13
25,877			7,173,142		14
			3,337,422		15
5,908,590			527,219,064		16
					17
					18
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5,908,590			527,219,064		46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	26,133,793	824,021
49	(352) Structures and Improvements	6,237,315	141,133
50	(353) Station Equipment	134,930,698	12,900,803
51	(354) Towers and Fixtures	92,322,957	2,400,232
52	(355) Poles and Fixtures	40,893,623	7,822,496
53	(356) Overhead Conductors and Devices	101,592,802	7,632,123
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)	402,228,844	31,720,808
59	4. DISTRIBUTION PLANT		
60	(360) Land and Land Rights	5,559,422	852,189
61	(361) Structures and Improvements	4,152,084	121,240
62	(362) Station Equipment	47,782,459	1,222,878
63	(363) Storage Battery Equipment		
64	(364) Poles, Towers, and Fixtures	140,990,748	7,948,638
65	(365) Overhead Conductors and Devices	122,052,270	10,259,055
66	(366) Underground Conduit	3,970,629	332,819
67	(367) Underground Conductors and Devices	7,126,536	578,819
68	(368) Line Transformers	93,274,770	7,450,618
69	(369) Services	36,067,832	2,815,091
70	(370) Meters	21,022,480	2,963,122
71	(371) Installations on Customer Premises	17,591,629	1,469,673
72	(372) Leased Property on Customer Premises		
73	(373) Street Lighting and Signal Systems	2,895,523	141,474
74	(374) Asset Retirement Costs for Distribution Plant		
75	TOTAL Distribution Plant (Enter Total of lines 60 thru 74)	502,486,382	36,155,616
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	1,556,493	182,231
87	(390) Structures and Improvements	19,853,744	76,196
88	(391) Office Furniture and Equipment	1,311,322	17,320
89	(392) Transportation Equipment	9,655	
90	(393) Stores Equipment	121,017	35,994
91	(394) Tools, Shop and Garage Equipment	2,029,501	624,982
92	(395) Laboratory Equipment	281,771	
93	(396) Power Operated Equipment	5,931	
94	(397) Communication Equipment	5,450,977	1,320,537
95	(398) Miscellaneous Equipment	934,117	42,241
96	SUBTOTAL (Enter Total of lines 86 thru 95)	31,554,528	2,299,501
97	(399) Other Tangible Property		
98	(399.1) Asset Retirement Costs for General Plant		
99	TOTAL General Plant (Enter Total of lines 96, 97 and 98)	31,554,528	2,299,501
100	TOTAL (Accounts 101 and 106)	1,431,480,773	130,789,509
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)	1,431,480,773	130,789,509

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

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

Retirements (d)	Adjustments (e)	Transfers (f)	Balance at End of Year (g)		Line No.
					47
282,500			26,675,314		48
8,548			6,369,900		49
1,369,350		-3,661	146,458,490		50
646			94,722,543		51
331,275			48,384,844		52
149,255			109,075,670		53
			11,590		54
			106,066		55
					56
					57
2,141,574		-3,661	431,804,417		58
					59
			6,411,611		60
206			4,273,118		61
197,774		3,661	48,811,224		62
					63
1,315,032			147,624,354		64
3,155,687			129,155,638		65
694			4,302,754		66
53,234			7,652,121		67
2,310,335			98,415,053		68
720,680			38,162,243		69
1,023,535			22,962,067		70
1,060,049			18,001,253		71
					72
97,394			2,939,603		73
					74
9,934,620		3,661	528,711,039		75
					76
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					84
					85
31,762			1,706,962		86
19,618			19,910,322		87
15,821			1,312,821		88
			9,655		89
14,160			142,851		90
75,087			2,579,396		91
19,393			262,378		92
			5,931		93
16,506			6,755,008		94
2,038			974,320		95
194,385			33,659,644		96
					97
					98
194,385			33,659,644		99
18,516,052			1,543,754,230		100
					101
					102
					103
18,516,052			1,543,754,230		104

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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	/ /	End of 2008/Q4

ELECTRIC PLANT HELD FOR FUTURE USE (Account 105)

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

Line No.	Description and Location Of Property (a)	Date Originally Included in This Account (b)	Date Expected to be used in Utility Service (c)	Balance at End of Year (d)
1	Land and Rights:			
2	Carrs Site (8500)	08/17/82		6,778,355
3				
4				
5				
6				
7	Items under $250,000			30,592
8				
9				
10				
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21	Other Property:			
22	None to Report			
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47	Total			6,808,947

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	STATE OF KENTUCKY	
2	BS 2 Replace Catalyst For SCR	1,092,643
3	KP/ R/W Widening	2,579,856
4	EIMS: GHG & TITLE V MODEL	210,641
5	KP/Trans CKT Reliab Program	156,332
6	Circuit Breaker Rehab Program-KYPCo	456,694
7	KYP- Relay Rehab Projects	823,551
8	KYP- RTU replacement prog	568,685
9	KYP RTU replacement prog	366,009
10	KYP- Line Rehab Program	2,388,135
11	Big Sandy Unit 1 Turbine Retrofit	2,619,686
12	TL/KEP/ROW 4 Mile 138 kV Ext	699,153
13	AOD & SCR Year Round Oper Rev	734,726
14	TS/KY/Thelma Sta-Inst 138/69	755,042
15	TL/Paintsvill Const 69kV Line	227,136
16	DS/KY/Paintsville Const 69/12k	974,468
17	TS/Dewey Station - Remote	174,363
18	DS/KYP/Thelma-Paintsville	117,346
19	KPCo Hg Monitoring Project- Bi	1,455,151
20	TL/KYP/Henry Clay - Elkhorn Ci	1,296,528
21	T/KYPCO/Metering Upgrade KY	1,007,201
22	DS/KYP/Metering Upgrade KY	198,214
23	TS/KYP/Lesile Station add 16	911,723
24	KY/Cutout-Arrester	243,606
25	Energy Mgmt Sys-Kentucky Power	122,898
26	KP Install AMR Demand Meters	117,867
27	BS U1 SNCR (NSR)	152,096
28	Replace lower furnace U1	185,734
29	Air Heater Basket Repl U1	1,169,238
30	KY/Soft Schell Sta 34kV Fdrs	593,217
31	KY/Soft Shell Sta 138-34kV	2,313,182
32	KY/Soft Schell 138kV Line	224,152
33	KY/Beaver Ck Remote End Relay	275,498
34	KY/Hitchins Rebuild Station	2,577,219
35	KY/Hitchins Sta Relocate T Lin	130,227
36	KY/Busseyville Sta Add 2nd Xfm	2,083,390
37	KY/Busseyville Sta Torchlight	414,135
38	KP/Beaver Ck Svc Black Diamond	348,906
39	KY/Cannonsburg Distr Auto	812,129
40	KY/Collier Sta 34kV to Equitab	143,288
41	Ds-Kp-Ai Pole Replacement	151,524
42	Extension of Fly Ash Retention Dam	695,299
43	TOTAL	46,649,955

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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 $100,000, whichever is less) may be grouped.

Line No.	Description of Project (a)	Construction work in progress - Electric (Account 107) (b)
1	WS-CI-KEPCo-G PPB	5,860,890
2	ET-CI-KEPCo-T CUST SERV	272,854
3	ET-CI-KEPCo-T SYS IMP	727,412
4	ED-CI-KEPCo-D AST IMP	2,538,036
5	ED-CI-KEPCo-D CUST MTR	252,743
6	ED-CI-KEPCo-D CUST SERV	931,124
7	ED-CI-KEPCo-D LN TRNSF	318,284
8	SS-CI-KEPCo-G GEN PLT	126,508
9	WS-KEPCo-G	362,246
10	ET-KEPCo-T	189,544
11	ED-KEPCo-D	556,550
12	SS-CI-KyPCo-D Software	138,728
13	SS-CI-KyPCo-G Software	238,194
14	ET-CI-KyPCo-T Drvn D Asset Imp	414,378
15	Other Minor Projects under $100,000	1,155,576
16	TOTAL STATE OF KENTUCKY: $46,649,955	
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43	TOTAL	46,649,955

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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	470,175,005	470,175,005		
2	Depreciation Provisions for Year, Charged to				
3	(403) Depreciation Expense	43,555,013	43,555,013		
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):	11,009	11,009		
9					
10	TOTAL Deprec. Prov for Year (Enter Total of lines 3 thru 9)	43,566,022	43,566,022		
11	Net Charges for Plant Retired:				
12	Book Cost of Plant Retired	18,177,057	18,177,057		
13	Cost of Removal	20,289,590	20,289,590		
14	Salvage (Credit)	7,442,923	7,442,923		
15	TOTAL Net Chrgs. for Plant Ret. (Enter Total of lines 12 thru 14)	31,023,724	31,023,724		
16	Other Debit or Cr. Items (Describe, details in footnote):	3,121,172	3,121,172		
17					
18	Book Cost or Asset Retirement Costs Retired				
19	Balance End of Year (Enter Totals of lines 1, 10, 15, 16, and 18)	485,838,475	485,838,475		
	Section B. Balances at End of Year According to Functional Classification				
20	Steam Production	210,169,120	210,169,120		
21	Nuclear Production				
22	Hydraulic Production-Conventional				
23	Hydraulic Production-Pumped Storage				
24	Other Production				
25	Transmission	135,462,933	135,462,933		
26	Distribution	133,637,433	133,637,433		
27	Regional Transmission and Market Operation				
28	General	6,568,989	6,568,989		
29	TOTAL (Enter Total of lines 20 thru 28)	485,838,475	485,838,475		

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

ARO asbestos depreciation expense reclass to account 1080013 $11,009

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

RWIP transferred to In-Service	$3,184,985
ARO asbestos reclassed to account 1080013	$ -63,813
TOTAL	$3,121,172

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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	/ /	End of 2008/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)	8,174,520	29,070,196	Electric
2	Fuel Stock Expenses Undistributed (Account 152)	163,093	370,203	Electric
3	Residuals and Extracted Products (Account 153)			
4	Plant Materials and Operating Supplies (Account 154)			
5	Assigned to - Construction (Estimated)	7,926,308	7,149,031	Electric
6	Assigned to - Operations and Maintenance			
7	Production Plant (Estimated)	654,855	1,349,928	Electric
8	Transmission Plant (Estimated)	74,513	38,016	Electric
9	Distribution Plant (Estimated)	345,151	183,022	Electric
10	Regional Transmission and Market Operation Plant (Estimated)			
11	Assigned to - Other (provide details in footnote)	75,712	94,928	Electric
12	TOTAL Account 154 (Enter Total of lines 5 thru 11)	9,076,539	8,814,925	
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)	17,414,152	38,255,324	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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.	Allowances Inventory (Account 158.1) (a)	Current Year No. (b)	Current Year Amt. (c)	2009 No. (d)	2009 Amt. (e)
1	Balance-Beginning of Year	1,508,339.00	2,681,113	42,838.00	996,869
2					
3	Acquired During Year:				
4	Issued (Less Withheld Allow)	7,394,724.00		9,684.00	
5	Returned by EPA				
6					
7					
8	Purchases/Transfers:				
9	Chicago Climate Exchange	2,087.00	5,114		
10	Indiana Michigan Power Co	82.00	34,907		
11	Ohio Power Company (SO2)	11,223.00			
12	Northern Indiana Public			2,859.00	115,848
13	Bear Energy LP				
14					
15	Total	13,392.00	40,021	2,859.00	115,848
16					
17	Relinquished During Year:				
18	Charges to Account 509	8,027,708.00	1,844,700		
19	Other:				
20	Write off existing CO2	856,773.00	2,840	648.00	3,212
21	Cost of Sales/Transfers:				
22	AEP System Pool	1,932.00	52,236		
23	Northern Indiana Public	2,826.00	115,423		
24	Evolution Markets LLC				
25	Bear Energy LP				
26	Amrex Emissions LTD	200.00			
27	Other				
28	Total	4,958.00	167,659		
29	Balance-End of Year	27,016.00	705,935	54,733.00	1,109,505
30					
31	Sales:				
32	Net Sales Proceeds(Assoc. Co.)		52,235		
33	Net Sales Proceeds (Other)		246,413		
34	Gains		130,991		
35	Losses				
	Allowances Withheld (Acct 158.2)				
36	Balance-Beginning of Year	503.00		503.00	
37	Add: Withheld by EPA				
38	Deduct: Returned by EPA				
39	Cost of Sales	503.00			
40	Balance-End of Year			503.00	
41					
42	Sales:				
43	Net Sales Proceeds (Assoc. Co.)				
44	Net Sales Proceeds (Other)		196,768		
45	Gains		196,768		
46	Losses				

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.

2010		2011		Future Years		Totals		Line
No. (f)	Amt. (g)	No. (h)	Amt. (i)	No. (j)	Amt. (k)	No. (l)	Amt. (m)	No.
42,732.00	729,244	42,614.00	1,096,230	930,630.00	4,903,964	2,567,153.00	10,407,420	1
								2
								3
10,610.00		10,610.00		66,775.00		7,492,403.00		4
								5
								6
								7
								8
						2,087.00	5,114	9
						82.00	34,907	10
						11,223.00		11
						2,859.00	115,848	12
		1,383.00	23,213			1,383.00	23,213	13
								14
		1,383.00	23,213			17,634.00	179,082	15
								16
								17
						8,027,708.00	1,844,700	18
								19
648.00	3,212					858,069.00	9,264	20
								21
						1,932.00	52,236	22
						2,826.00	115,423	23
17.00	293	189.00	4,809	5,103.00	21,546	5,309.00	26,648	24
1,383.00	23,859					1,383.00	23,859	25
						200.00		26
								27
1,400.00	24,152	189.00	4,809	5,103.00	21,546	11,650.00	218,166	28
51,294.00	701,880	54,418.00	1,114,634	992,302.00	4,882,418	1,179,763.00	8,514,372	29
								30
								31
							52,235	32
	1,793		19,940		288,886		557,032	33
	1,500		15,131		267,340		414,962	34
								35
503.00		503.00		23,055.00		25,067.00		36
				1,006.00		1,006.00		37
								38
				503.00		1,006.00		39
503.00		503.00		23,558.00		25,067.00		40
								41
								42
								43
					68,653		265,421	44
					68,653		265,421	45
								46

Schedule Page: 228 Line No.: 20 Column: a

Since 2003, Kentucky Power, has included carbon dioxide (CO2) allowances in account 158.1, along with sulfur dioxide (SO2) and nitrous oxide (NOx) allowances. The SO2 and NOx allowances are reported in tons. The CO2 allowances are reported in metric tons. Beginning December 1, 2008 and continuing prospectively, Kentucky Power, will account for purchases of CO2 allowances by expensing them immediately upon purchase. All CO2 allowance inventory was written off at November 30, 2008.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

Transmission Service and Generation Interconnection Study Costs

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

Line No.	Description (a)	Costs Incurred During Period (b)	Account Charged (c)	Reimbursements Received During the Period (d)	Account Credited With Reimbursement (e)
1	**Transmission Studies**				
2					
3	S56-Beaver Creek - Hazard 138 KV				
4	KY Mount. Power	82	186	84	186
5					
6	#U2-080 South - Portsmouth				
7	138KV Feasibility Study	1,779	186	1,334	186
8					
9					
10					
11					
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20					
21	**Generation Studies**				
22					
23	Big Sandy 1 - PJM Gen Int Study	139	500		
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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	/ /	End of 2008/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 $50,000 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	Merger Costs	298,011		407	298,011	
2	Amortz period: Aug 2000-July 2008					
3						
4	SFAS 109 Deferred FIT	77,221,963	14,897,110	190/282-3	11,332,080	80,786,993
5						
6	SFAS 109 Deferred SIT	27,643,000	4,625,364	283	2,313,812	29,954,552
7						
8	Post In-Service AFUDC Hanging Rock/	832,680		406	33,408	799,272
9	Jefferson 765 KV Line					
10	Amortz period: Dec 1984-Nov 2032					
11						
12	Depreciation Expenses - Hanging Rock/	129,769		406	5,208	124,561
13	Jefferson 765 KV line					
14	Amortz period: Dec 1984-Nov 2032					
15						
16	Deferred DSM Expenses	50,222	1,179,111	Various	1,074,994	154,339
17						
18	Unrealized Loss on Forward Commitments	765,079	52,427,917	Various	53,192,996	
19						
20	Deferred Equity Carrying Charges	(219,825)	22,428			-197,397
21						
22	BridgeCo Transmission Org Funding	375,685		407	18,830	356,855
23	Amortz period: Jan 2005-Dec 2019					
24	FERC Docket AC04-101-000					
25						
26	PJM Integration Payments	806,206		407	91,486	714,720
27	Amortz period: Jan 2005-Dec 2014					
28	FERC Docket EL05-74-000					
29						
30	Other PJM Integration	396,910		407	19,895	377,015
31	Amortz period: Jan 2005-Dec 2019					
32	FERC Docket AC04-101-000					
33						
34	Carrying Charges - RTO Startup Costs	272,762	150,192	407	171,448	251,506
35	Amortz period: Jan 2005 up to Dec 2019					
36	FERC Docket AC04-101-000					
37						
38	Alliance RTO Deferred Expense	196,629		407	9,856	186,773
39	Amortz period: Jan 2005-Dec 2019					
40	FERC Docket AC04-101-000					
41						
42	Unrecovered Fuel Costs	4,425,464	125,001,415	254,501	119,473,715	9,953,164
43						
44	TOTAL	131,939,930	248,763,829		188,921,651	191,782,108

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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 $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Assets being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Assets (a)	Balance at Beginning of Current Quarter/Year (b)	Debits (c)	CREDITS Written off During the Quarter/Year Account Charged (d)	CREDITS Written off During the Period Amount (e)	Balance at end of Current Quarter/Year (f)
1	SFAS 112 Post Employment Benefit	5,172,173	1,708,452			6,880,625
2						
3	SFAS 158 Employers' Accounting for Defined	13,573,202	48,751,840	Various	885,912	61,439,130
4	Benefit Pension and Other Postretirement Plans					
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43						
44	TOTAL	131,939,930	248,763,829		188,921,651	191,782,108

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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 $50,000, 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	7,922,000	8,738,119	408	7,957,118	8,703,001
2						
3	Agency Fees - Factored A/R	827,950	9,968,531	Various	9,680,105	1,116,376
4						
5	Labor Accrual - Balance Sheet	591,435	9,852,884	Various	9,783,651	660,668
6						
7	Unamortized Credit Line Fees	183,438	26,442	431	56,516	153,364
8						
9	Miscellaneous Items		75			75
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46						
47	Misc. Work in Progress	1,023,021				1,086,095
48	Deferred Regulatory Comm. Expenses (See pages 350 - 351)					
49	TOTAL	10,547,844				11,719,579

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	4,830,451	5,605,105
3	Contribution-In-Aid Of Construction	2,703,071	2,730,527
4	Mark-To-Market	4,527,783	10,564,780
5	Pension	-5,573,357	-5,338,365
6	SFAS 106 Post Retirement Expenses	2,604,169	2,179,660
7	Other	13,178,249	26,975,554
8	TOTAL Electric (Enter Total of lines 2 thru 7)	22,270,366	42,717,261
9	Gas		
10			
11			
12			
13			
14			
15	Other		
16	TOTAL Gas (Enter Total of lines 10 thru 15		
17	Other (Specify)	12,766,496	13,801,536
18	TOTAL (Acct 190) (Total of lines 8, 16 and 17)	35,036,862	56,518,797

Notes

Page 234 Line 17	Beginning of Year	End of Year
Non-Utility - Acct 190.2	156,236	1,096,812
SFAS 109	12,096,890	12,341,885
SFAS 133	510,370	362,839
	12,766,496	13,801,536

Summary:

1901001	Accum DFIT - Other	42,717,261
1902001	Accum DFIT - Other Income & Deductions	1,096,812
1903001	Accum DFIT - SFAS 109 Flow-Thru	11,840,650
1904001	Accum DFIT - SFAS 109 Excess	501,235
	SubTotal A/C 190	56,155,958
1900006	SFAS 133 Non-Affil Fed Accum DFIT	80,872
1900015	ADIT-Fed-Hdg-CF-Int Rate	281,967
	TOTAL A/C 190	56,518,797

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

CAPITAL STOCKS (Account 201 and 204)

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

Line No.	Class and Series of Stock and Name of Stock Series (a)	Number of shares Authorized by Charter (b)	Par or Stated Value per share (c)	Call Price at End of Year (d)
1	Common Stock	2,000,000	50.00	
2				
3				
4				
5				
6				
7				
8				
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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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
						5
						6
						7
						8
						9
						10
						11
						12
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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	/ /	End of 2008/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	208,750,000
3		
4	Subtotal - Account 208	208,750,000
5		
6	Account 209 - Reduction in Par or Stated Value of Capital Stock	
7		
8	Account 210 - Gain on Resale/Cancellation of Reacquired Capital Stock	
9		
10	Account 211 - Miscellaneous Paid-In-Capital	
11		
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39		
40	TOTAL	208,750,000

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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			626,250 D
16			
17	Senior Unsecured Notes - 6.000%, Series E	325,000,000	2,277,883
18	KPSC Authority Docket No.2006-0034		1,667,250 D
19			
20	Senior Unsecured Notes - 6.450%, Series A	30,000,000	51,517
21			187,500 D
22			
23			
24			
25			
26			
27			
28			
29			
30			
31			
32	SUBTOTAL ACCOUNT 224 - OTHER LONG-TERM DEBT	430,000,000	5,546,975
33	TOTAL	450,000,000	5,546,975

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

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

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

Nominal Date of Issue (d)	Date of Maturity (e)	AMORTIZATION PERIOD Date From (f)	Date To (g)	Outstanding (Total amount outstanding without reduction for amounts held by respondent) (h)	Interest for Year Amount (i)	Line No.
						1
						2
						3
						4
						5
						6
						7
						8
						9
02/05/2004	06/01/2015			20,000,000	1,050,000	10
				20,000,000	1,050,000	11
						12
						13
06/13/2003	12/01/2032	06/13/2003	12/01/2032	75,000,000	4,218,750	14
						15
						16
09/11/2007	09/15/2017	09/11/2007	09/15/2017	325,000,000	19,500,000	17
						18
						19
11/10/1998	11/10/2008	11/10/1998	11/10/2008		1,660,875	20
						21
						22
						23
						24
						25
						26
						27
						28
						29
						30
						31
				400,000,000	25,379,625	32
				420,000,000	26,429,625	33

Schedule Page: 256   Line No.: 21   Column: i

The difference between the total interest on this schedule and the total of accounts 427 and 430 is due to interest on short-term advances from the AEP Money Pool and interest of $5,827,595 on reallocated off-system sales margins between the AEP East and West companies as ordered by the FERC.

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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)	24,531,321
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	18,008,006
28	Show Computation of Tax:	
29		
30		
31		
32		
33		
34		
35		
36		
37		
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40		
41		
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43		
44		

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

		In (000's)
Net Income for the year per Page 117		24,531
Federal Income Taxes		6,246
State Income Taxes		1,650
Pretax Book Income		32,427
Increase (Decrease) in Taxable Income resulting from:		
Allowance for Funds Used During Construction and Other Differences between Items Capitalized for Books and Expensed for Tax		220
Capitalized Relocation Costs		(108)
Deferred Fuel Costs (Net)		4,776
Demand Side Management (Net)		(104)
Emission Allowances (Net)		(322)
Excess Tax Vs. Book Depreciation		(26,438)
Mark-to-Market		3,544
Merger Costs		290
Pension Expenses (Net)		956
RTO Expenses and Carrying Charges		141
Removal Costs - ACRS		(11,743)
Repair Allowance		(300)
Self Insurance - Book Reserve		(51)
SFAS 106 - Post Retirement Benefit Expense Accrued/Funded (Net)		(101)
Tax Accruals and Deferrals		(18)
Pollution Control Equipment		(2,376)
Accrd Book ARO Exp		2,330
Misc Book Accruals and Deferrals		1
Provision for Possible Revenue Refunds		19,461
Sales & Use Tax Reserves		(59)
Accrued Tax Reserve - FIN 48		106
Accrued Interest - Long & Short Term		(1,759)
Mitigation Programs - Federal & State		(557)
Non-Deductible Fines & Penalties		(75)
Other (Net)		(79)
Federal Taxable Income before State Income Taxes		20,162
Less: State Income Taxes		2,154
Federal Taxable Net Income - Estimated Current Year Taxable Income (Separate Return Basis)		18,008
		========
Computation of Tax *		
Federal Income Tax on Current Year Taxable Income (Separate Return Basis) at the Statutory Rate of 35%		6,303
Adjustment due to System Consolidation	(a)	(267)
Other Adjustments to Retained Earnings		196
Audit Settlement Adjustment		0
Estimated Tax Currently Payable	(b)	6,232
Adjustments of Prior Year's Accruals (Net)		(3,208)
Estimated Current Federal Income Taxes (Net)		3,024
		========

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

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

INSTRUCTION 2.

* The tax computation above represents an estimate of the Company's allocated portion of the System consolidated Federal income tax. The computation of actual 2008 System Federal income taxes will not be available until the consolidated Federal income tax return is completed and filed by September 2009. The actual allocation of the System consolidated Federal income tax to the members of the consolidated group will not be available until after the consolidated Federal income tax return is filed.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	-812,507		3,024,254	1,430,000	-197,889
3	INCOME TAX - FIN 48	374,180				-100
4	FICA - 2008	407,952		2,979,558	2,960,758	
5	Unemployment - 2008	12,815		31,429	28,692	
6						
7	Federal Excise Tax - Audit			9,054	9,054	
8	Federal Excise Tax - 2008			2,029	2,029	
9						
10	STATE INC. TAX - FIN 48	545,618		148,890		95,532
11						
12	STATE OF KENTUCKY:					
13	Income 2006 & Prior	257,051		31,650	288,701	
14	2007	432,970		-433,840	-870	
15	2008			1,846,987	1,779,870	
16						
17	License Fee - 2008			115	100	-15
18						
19	Unemployment - KY 2008	8,159		27,832	24,064	
20						
21	PUBLIC SER COMM'S-2007		339,379	339,379		
22	PUBLIC SER COMM'S-2008			335,183	670,366	
23						
24	SALES & USE TAX - 2007	163,275		-37,562	125,713	
25	SALES & USE TAX - 2008			1,313,358	1,266,508	
26	SALES & USE TAX - Audits	1,492,200		362,456	421,586	
27						
28	REAL & PERS PROP-2004			31	31	
29	REAL & PERS PROP-2005	40,443		129,636	170,078	
30	REAL & PERS PROP-2006	6,019,874		-1,569,059	4,467,426	
31	REAL & PERS PROP-2007	7,922,000			7,373,022	
32	REAL & PERS PROP-2008			8,703,001		
33	PERS PROP LEASED-2006	5,728		-5,367	361	
34	PERS PROP LEASED-2007	32,112		-12,471	19,664	
35	PERS PROP LEASED-2008			35,118	32,116	
36	REAL PROP LEASED-2007	3,389		1,019	4,408	
37	REAL PROP LEASED-2008			12,020	11,156	
38						
39	STATE OF WEST VIRGINIA:					
40	Income 2006 & Prior	-99		5,008	4,909	
41	TOTAL	16,981,490	339,379	17,527,749	21,376,086	-102,472

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
						1
583,858		3,618,871			-594,617	2
374,080						3
426,752		1,854,341			1,125,217	4
15,552		19,389			12,040	5
						6
		7,501			1,553	7
		2,029				8
						9
790,040		148,890				10
						11
						12
		31,650				13
		-453,161			19,321	14
67,117		1,794,975			52,012	15
						16
		115				17
						18
11,927		16,928			10,904	19
						20
		339,379				21
	335,183	335,183				22
						23
		2,405			-39,967	24
46,850		25,116			1,288,242	25
1,433,070		334,411			28,045	26
						27
		31				28
		129,636				29
-16,611		-1,569,059				30
548,978		7,922,000			-7,922,000	31
8,703,001					8,703,001	32
		-5,367				33
-22		-12,471				34
3,002		35,118				35
		1,019				36
864		12,020				37
						38
						39
		5,008				40
13,026,485	335,183	14,834,484			2,693,265	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	2007	192		-12,889	-12,697	
2	2008			47,366	44,397	
3						
4	Franchise - 2007	-332		-57,439	-57,771	
5	2008			59,800	98,671	
6						
7	SALES/USE - 2007	322		-322		
8	SALES/USE - 2008			2,252		
9						
10	REAL & PERS PROP-2007			1,025	1,025	
11	PERS PROP LEASED-2006			4,908	4,908	
12	PERS PROP LEASED-2007			1,530	1,530	
13	License Fee - 2007					
14						
15	WV State Unemployment -	2,119		1,384	1,080	
16						
17	STATE OF OHIO:					
18	Income 2007	32,029		-57,191	-25,162	
19	2008			5,144	31,335	
20						
21	Franchise 2007					
22	Franchise 2008			31,575	33,827	
23						
24	License Fee - 2008			25	25	
25						
26	OH CAT TAX - 2007	42,000		-25,603	16,397	
27	OH CAT TAX - 2008			177,578	147,578	
28						
29	STATE OF VIRGINIA:					
30	VA State Unemployment					
31						
32	STATE OF MICHIGAN:					
33	Income 2008			68,697	1,000	
34						
35	License Fee - 2007					
36						
37	OTHER:					
38	REAL/PERS PROP-LA-2008			201	201	
39						
40						
41	TOTAL	16,981,490	339,379	17,527,749	21,376,086	-102,472

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TAXES ACCRUED, PREPAID AND CHARGED DURING YEAR (Continued)

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

BALANCE AT END OF YEAR		DISTRIBUTION OF TAXES CHARGED				Line No.
(Taxes accrued Account 236) (g)	Prepaid Taxes (Incl. in Account 165) (h)	Electric (Account 408.1, 409.1) (i)	Extraordinary Items (Account 409.3) (j)	Adjustments to Ret. Earnings (Account 439) (k)	Other (l)	
		-13,849			960	1
2,969		44,690			2,676	2
						3
		-57,439				4
-38,871		59,800				5
						6
					-322	7
2,252					2,252	8
						9
		1,025				10
		4,908				11
		1,530				12
						13
						14
2,423		893			491	15
						16
						17
		-58,784			1,593	18
-26,191		4,042			1,102	19
						20
						21
-2,252		31,575				22
						23
		25				24
						25
		-25,603				26
30,000		177,578				27
						28
						29
						30
						31
						32
67,697		67,935			762	33
						34
						35
						36
						37
		201				38
						39
						40
13,026,485	335,183	14,834,484			2,693,265	41

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ACCUMULATED DEFERRED INVESTMENT TAX CREDITS (Account 255)

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

Line No.	Account Subdivisions (a)	Balance at Beginning of Year (b)	Deferred for Year Account No. (c)	Deferred for Year Amount (d)	Allocations to Current Year's Income Account No. (e)	Allocations to Current Year's Income Amount (f)	Adjustments (g)
1	Electric Utility						
2	3%						
3	4%	287			411.4	287	
4	7%						
5	10%	3,394,219			411.4	874,899	
6							
7							
8	TOTAL	3,394,506				875,186	
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							
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47							
48							

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

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

Balance at End of Year (h)	Average Period of Allocation to Income (i)	ADJUSTMENT EXPLANATION	Line No.
			1
			2
	Various		3
			4
2,519,320	Various		5
			6
			7
2,519,320			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
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			44
			45
			46
			47
			48

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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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 $10,000, 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	41,433	454	581,296	584,106	44,243
2						
3	Accrued Penalties - Tax Reserves	333,340				333,340
4						
5	Allowances		Various	452,241	452,241	
6						
7	Customer Advance Receipts	943,204	142, 143	6,680,946	6,262,602	524,860
8						
9	Deferred Gain:	182,261	124	2,990		179,271
10	Fiber Optic Agrmts-In Kind Svc					
11	Amortize through June 2026					
12						
13	Deferred Revenue	184,508	451	13,555		170,953
14	Fiber Optic Lines-Sold-Defd Rev					
15	Amortize through January 2025					
16						
17	IPP - System Upgrade Credits	214,494			13,727	228,221
18						
19	Miscellaneous	18,169	Various	236,544	218,390	15
20						
21	State Mitigation Deferral (NSR)	1,629,600	242	651,840		977,760
22						
23	Federal Mitigation Deferral (NSR)	2,308,600	242	681,444		1,627,156
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	5,855,609		9,300,856	7,531,066	4,085,819

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	31,958,064	834,315	
5	Other (provide details in footnote):			
6				
7				
8	TOTAL Electric (Enter Total of lines 3 thru 7)	31,958,064	834,315	
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)	31,958,064	834,315	
18	Classification of TOTAL			
19	Federal Income Tax	31,958,064	834,315	
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	/ /	End of 2008/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
						32,792,379	4
							5
							6
							7
						32,792,379	8
							9
							10
							11
							12
							13
							14
							15
							16
						32,792,379	17
							18
						32,792,379	19
							20
							21

NOTES (Continued)

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER PROPERTY (Account 282)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 282			
2	Electric	116,973,454	19,975,203	5,400,057
3	Gas			
4				
5	TOTAL (Enter Total of lines 2 thru 4)	116,973,454	19,975,203	5,400,057
6	SFAS 109	49,091,077		
7				
8				
9	TOTAL Account 282 (Enter Total of lines 5 thru	166,064,531	19,975,203	5,400,057
10	Classification of TOTAL			
11	Federal Income Tax	166,064,531	19,975,203	5,400,057
12	State Income Tax			
13	Local Income Tax			

NOTES

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

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
						131,548,600	2
							3
							4
						131,548,600	5
				182, 254	2,489,604	51,580,681	6
							7
							8
					2,489,604	183,129,281	9
							10
					2,489,604	183,129,281	11
							12
							13

NOTES (Continued)

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ACCUMULATED DEFFERED INCOME TAXES - OTHER (Account 283)

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

Line No.	Account (a)	Balance at Beginning of Year (b)	CHANGES DURING YEAR Amounts Debited to Account 410.1 (c)	CHANGES DURING YEAR Amounts Credited to Account 411.1 (d)
1	Account 283			
2	Electric			
3	Deferred Fuel Costs	3,910,553	8,347,391	7,350,101
4	Mark to Market	5,273,964	12,511,543	8,270,698
5	Capitalized Software - Book	1,762,426	238,550	278,692
6	SFAS 158	2,698,352	132,696	409,789
7	Reg Asset - SFAS 112	1,810,258	597,962	
8	Other	2,257,590	2,174,459	2,409,791
9	TOTAL Electric (Total of lines 3 thru 8)	17,713,143	24,002,601	18,719,071
10	Gas			
11				
12				
13				
14				
15				
16				
17	TOTAL Gas (Total of lines 11 thru 16)			
18	Other	66,225,684		
19	TOTAL (Acct 283) (Enter Total of lines 9, 17 and 18)	83,938,827	24,002,601	18,719,071
20	Classification of TOTAL			
21	Federal Income Tax	56,295,827	24,002,601	18,719,071
22	State Income Tax	27,643,000		
23	Local Income Tax			

NOTES

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

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

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

CHANGES DURING YEAR		ADJUSTMENTS				Balance at End of Year	Line No.
Amounts Debited to Account 410.2	Amounts Credited to Account 411.2	Debits		Credits			
		Account Credited	Amount	Account Debited	Amount		
(e)	(f)	(g)	(h)	(i)	(j)	(k)	
							1
							2
						4,907,843	3
						9,514,809	4
						1,722,284	5
						2,421,259	6
						2,408,220	7
		190	-4,785,000			6,807,258	8
			-4,785,000			27,781,673	9
							10
							11
							12
							13
							14
							15
							16
							17
739,939	736,803			Various	4,690,973	70,919,793	18
739,939	736,803		-4,785,000		4,690,973	98,701,466	19
							20
739,939	736,803		-4,785,000		2,379,421	68,746,914	21
					2,311,552	29,954,552	22
							23

NOTES (Continued)

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

Page 276 Line 18 - Other

	Beginning Balance	Ending Balance
Non-Utility	1,807,642	1,810,778
SFAS 109	64,345,736	68,714,093
SFAS 133	72,306	394,922
	66,225,684	70,919,793

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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 $50,000 which ever is less), may be grouped by classes.
3. For Regulatory Liabilities being amortized, show period of amortization.

Line No.	Description and Purpose of Other Regulatory Liabilities (a)	Balance at Begining of Current Quarter/Year (b)	DEBITS Account Credited (c)	DEBITS Amount (d)	Credits (e)	Balance at End of Current Quarter/Year (f)
1	Home Energy Assistance Program	340,580	Various	528,046	232,331	44,865
2						
3	SFAS 109 Deferred FIT	3,525,040	190/282/283	844,448	108,065	2,788,657
4						
5	Unrealized Gain on Forward Commitments	9,592,401	Various	176,041,067	178,145,276	11,696,610
6						
7	Green Pricing Option		557	94	138	44
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	TOTAL	13,458,021		177,413,655	178,485,810	14,530,176

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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.

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	189,933,625	166,818,286
3	(442) Commercial and Industrial Sales		
4	Small (or Comm.) (See Instr. 4)	112,339,794	99,471,412
5	Large (or Ind.) (See Instr. 4)	172,680,788	138,650,866
6	(444) Public Street and Highway Lighting	1,281,420	1,162,099
7	(445) Other Sales to Public Authorities		
8	(446) Sales to Railroads and Railways		
9	(448) Interdepartmental Sales		
10	TOTAL Sales to Ultimate Consumers	476,235,627	406,102,663
11	(447) Sales for Resale	208,027,416	189,932,938
12	TOTAL Sales of Electricity	684,263,043	596,035,601
13	(Less) (449.1) Provision for Rate Refunds	12,698,791	
14	TOTAL Revenues Net of Prov. for Refunds	671,564,252	596,035,601
15	Other Operating Revenues		
16	(450) Forfeited Discounts	1,681,161	1,669,389
17	(451) Miscellaneous Service Revenues	435,858	405,679
18	(453) Sales of Water and Water Power		
19	(454) Rent from Electric Property	11,312,172	3,592,481
20	(455) Interdepartmental Rents		
21	(456) Other Electric Revenues	2,056,147	435,213
22	(456.1) Revenues from Transmission of Electricity of Others	5,177,011	4,830,703
23	(457.1) Regional Control Service Revenues		
24	(457.2) Miscellaneous Revenues		
25			
26	TOTAL Other Operating Revenues	20,662,349	10,933,465
27	TOTAL Electric Operating Revenues	692,226,601	606,969,066

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

ELECTRIC OPERATING REVENUES (Account 400)

5. 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.)
6. See pages 108-109, Important Changes During Period, for important new territory added and important rate increase or decreases.
7. For Lines 2,4,5,and 6, see Page 304 for amounts relating to unbilled revenue by accounts.
8. 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
2,481,169	2,484,565	144,105	144,207	2
				3
1,428,742	1,445,809	29,730	29,687	4
3,321,760	3,174,047	1,432	1,436	5
10,231	10,085	379	375	6
				7
				8
				9
7,241,902	7,114,506	175,646	175,705	10
4,630,761	5,305,636	84	101	11
11,872,663	12,420,142	175,730	175,806	12
				13
11,872,663	12,420,142	175,730	175,806	14

Line 12, column (b) includes $ 2,612,932 of unbilled revenues.
Line 12, column (d) includes -28,286 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	/ /	End of 2008/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	2,461,328	183,691,832	143,995	17,093	0.0746
3	Res Service Load Management	3,450	205,464	109	31,651	0.0596
4	Residential Service TOD	70	5,126	1	70,000	0.0732
5	Small General Service					
6	Medium General Service					
7	All Outdoor Lighting	27,342	4,273,338			0.1563
8	Mark West HC					
9	Metering Adjustment		79,019			
10	Subtotal Billed	2,492,190	188,254,779	144,105	17,294	0.0755
11	Unbilled Revenue	-11,021	1,678,846			-0.1523
12	Total Residential	2,481,169	189,933,625	144,105	17,218	0.0766
13						
14	442 Commercial Sales					
15	Residential Service		36			
16	Small General Service	128,544	12,913,142	21,436	5,997	0.1005
17	Medium General Service	519,847	44,167,984	7,478	69,517	0.0850
18	Medium General Service TOD	2,346	180,730	75	31,280	0.0770
19	Large General Service	591,731	42,751,042	700	845,330	0.0722
20	Quantity Power	177,028	9,653,289	20	8,851,400	0.0545
21	Municipal Waterworks					
22	All Outdoor Lighting	15,038	1,904,877			0.1267
23	Mark West HC	7,840	545,004	20	392,000	0.0695
24	Estimated Revenue	72	5,586	1	72,000	0.0776
25	Metering Adjustment		58,261			
26	Subtotal Billed	1,442,446	112,179,951	29,730	48,518	0.0778
27	Unbilled Revenue	-13,704	159,843			-0.0117
28	Total Commercial	1,428,742	112,339,794	29,730	48,057	0.0786
29						
30	442 Industrial Sales					
31	Small General Service	5,278	508,423	791	6,673	0.0963
32	Medium General Service	37,482	3,089,269	362	103,541	0.0824
33	Large General Service	198,444	14,649,192	197	1,007,330	0.0738
34	Quantity Power	797,143	44,013,236	66	12,077,924	0.0552
35	Commercial & Industrial TOD	2,290,486	107,597,445	16	143,155,375	0.0470
36	All Outdoor Lighting	988	114,405			0.1158
37	Mark West HC					
38	Estimated Revenue	-4,564	1,873,941			-0.4106
39	Metering Adjustment		57,066			
40	Subtotal Billed	3,325,257	171,902,977	1,432	2,322,107	0.0517
41	TOTAL Billed	7,270,188	473,622,695	175,646	41,391	0.0651
42	Total Unbilled Rev.(See Instr. 6)	-28,286	2,612,932	0	0	-0.0924
43	TOTAL	7,241,902	476,235,627	175,646	41,230	0.0658

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	Unbilled Revenue	-3,497	777,811			-0.2224
2	*Total Industrial*	3,321,760	172,680,788	1,432	2,319,665	0.0520
3						
4	444 Public Street Lighting					
5	Small General Service	756	107,262	310	2,439	0.1419
6	Medium General Service	923	75,263	12	76,917	0.0815
7	Street Lighting	8,517	1,084,036	57	149,421	0.1273
8	All Outdoor Lighting	99	17,695			0.1787
9	Mark West HC					
10	Metering Adjustment		732			
11	Subtotal Billed	10,295	1,284,988	379	27,164	0.1248
12	Unbilled Revenue	-64	-3,568			0.0558
13	Total Public Street Lighting	10,231	1,281,420	379	26,995	0.1252
14						
15	Instruction 5. (See Footnote)					
16						
17						
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41	TOTAL Billed	7,270,188	473,622,695	175,646	41,391	0.0651
42	Total Unbilled Rev.(See Instr. 6)	-28,286	2,612,932	0	0	-0.0924
43	TOTAL	7,241,902	476,235,627	175,646	41,230	0.0658

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) / /	2008/Q4

FOOTNOTE DATA

Schedule Page: 304 Line No.: 7 Column: d

Per Instruction #3

Outdoor Lighting customers served by more than one rate schedule:

Residential	41,347
Commercial	7,224
Industrial	273
Public Street & Highway	35
Total	48,879

Schedule Page: 304 Line No.: 22 Column: d

Schedule Page: 304 Line No.: 36 Column: d

Schedule Page: 304.1 Line No.: 8 Column: d

Schedule Page: 304.1 Line No.: 15 Column: a

440 Residential		Fuel Clause
	Residential Service	10,805,466
	Res Service Load Management	14,135
	Residential Service TOD	336
	All Outdoor Lighting	140,253
	Unbilled	2,487,796
Total		13,447,986
442 Commercial		
	Residential Service	4
	Mark West HC	35,178
	Small General Service	586,286
	Medium General Service	2,428,357
	Medium General Service TOD	10,761
	Large General Service	2,794,029
	Quantity Power	860,779
	All Outdoor Lighting	77,340
	Estimated	1,215
	Unbilled	1,143,762
Total		7,937,711
442 Industrial		
	Small General Service	25,855
	Medium General Service	159,903
	Large General Service	937,254
	Quantity Power	3,838,296
	Commercial & Industrial TOD	9,439,623
	All Outdoor Lighting	5,117
	Estimated	1,533,205
	Unbilled	1,059,339
Total		16,998,592
444 Public Street Lighting		
	Small General Service	3,645

	Medium General Service	3,908
	Street Lighting	43,388
	All Outdoor Lighting	509
	Unbilled	2,305
Total		53,755

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classifi-cation (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	CITY OF OLIVE HILL	RQ	KPCO 52			
2	CITY OF VANCEBURG	RQ	KPCO 51			
3	CLEVELAND PUBLIC POWER	IF	Note 1			
4	NC ELECTRIC MEMBERSHIP CORP.	IF	Note 1			
5	TOWN OF FRONT ROYAL	IF	Note 1			
6	WOLVERINE POWER SUPPLY COOP	IF	Note 1			
7	CITY OF COLUMBUS	LF	Note 1			
8	NC ELECTRIC MEMBERSHIP CORP.	LF	Note 1			
9	CAROLINA POWER & LIGHT	LU	Note 1			
10	THE BOROUGH OF PITCAIRN, PA	SF	Note 1			
11	ABN AMRO, INC.	OS	Note 1			
12	AEP SERVICE CORPORATION	OS	Note 1			
13	AEP SERVICE CORPORATION	OS	Note 1			
14	ALLEGHENY ENERGY SUPPLY CO LLC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
28,275		1,579,877		1,579,877	1
71,823		3,687,086		3,687,086	2
10,249		491,061		491,061	3
64,134		2,274,210		2,274,210	4
12,173	508,819	310,423		819,242	5
61,488	239,153	2,620,325		2,859,478	6
64,873		3,493,829		3,493,829	7
123,460	2,567,717	2,159,237		4,726,954	8
20	490,580			490,580	9
		45,099		45,099	10
		-3		-3	11
2,330,614		62,641,958		62,641,958	12
		249,047		249,047	13
-32,299		-2,190,445		-2,190,445	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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 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	AMEREN ENERGY FUELS & SERVICES	OS	Note 1			
2	AMEREN ENERGY MARKETING	OS	Note 1			
3	AMERENCILCO,CIPS,AMEREN IP	OS	Note 1			
4	AMEREN-ILLINOIS POWER	OS	Note 1			
5	AMERICAN MUNICIPAL POWER-OHIO	OS	Note 1			
6	ARKANSAS ELECTRIC CO-OP CORP	OS	Note 1			
7	ASSOCIATED ELECT COOPERATIVE	OS	Note 1			
8	B.P. ENERGY COMPANY	OS	Note 1			
9	BALTIMORE GAS & ELECTRIC	OS	Note 1			
10	BARCLAYS BANK PLC	OS	Note 1			
11	BLUESTAR ENERGY SERVICES, INC.	OS	Note 1			
12	BNP PARIBAS COMMODITY FUTURES,	OS	Note 1			
13	BP AMOCO	OS	Note 1			
14	BUCKEYE POWER GENERATING, LLC	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

OS - for other service. use this category only for those services which cannot be placed in the above-defined categories, such as all non-firm service regardless of the Length of the contract and service from designated units of Less than one year. Describe the nature of the service in a footnote.
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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.
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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.
61		8,274		8,274	1
2,350		135,467		135,467	2
51		3,975		3,975	3
89		7,783		7,783	4
17,779		1,008,946		1,008,946	5
-22		-599		-599	6
-603		-19,102		-19,102	7
3,944		186,414		186,414	8
32,095		4,160,071		4,160,071	9
52,911		3,611,036		3,611,036	10
128		8,171		8,171	11
		-24		-24	12
		31,406		31,406	13
		-1,176,733		-1,176,733	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

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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) (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	BUCKEYE RURAL ELECTRIC ADMIN	OS	Note 1			
2	CALPINE POWER SERVICE COMPANY	OS	Note 1			
3	CAMP GROVE WIND FARM LLC	OS	Note 1			
4	CAROLINA POWER & LIGHT	OS	Note 1			
5	CHEVRON TEXACO	OS	Note 1			
6	CHEVRON USA INC	OS	Note 1			
7	CITADEL ENERGY INVESTMENTS LTD	OS	Note 1			
8	CITADEL ENERGY PRODUCTS LLC	OS	Note 1			
9	CITIGROUP ENERGY INC.	OS	Note 1			
10	CITIZENS ELECT CO & WELLSBOROU	OS	Note 1			
11	CITY OF COLUMBUS	OS	Note 1			
12	CITY OF DOWAGIAC, MI	OS	Note 1			
13	CITY OF LEBANON	OS	Note 1			
14	CITY OF NEW MARTINSVILLE	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SALES FOR RESALE (Account 447) (Continued)

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22,229		4,079,797		4,079,797	1
10,552		990,189		990,189	2
		681		681	3
2,742		200,335		200,335	4
		-3		-3	5
		-4,145		-4,145	6
		23,808		23,808	7
		96,565		96,565	8
8,309		615,641		615,641	9
		29,490		29,490	10
-636		-181,136		-181,136	11
5,100		384,661		384,661	12
20,862		1,461,708		1,461,708	13
2,637		102,147		102,147	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

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Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW): Average Monthly NCP Demand (e)	Actual Demand (MW): Average Monthly CP Demand (f)
1	CITY OF PHILIPPI, WEST VIRGINI	OS	Note 1			
2	COMED WHOLESALE MARKETING	OS	Note 1			
3	COMMERCE ENERGY, INC.	OS	Note 1			
4	COMMONWEALTH EDISON CO AUCTIO2	OS	Note 1			
5	CONECTIV ENERGY SUPPLY INC.	OS	Note 1			
6	CONOCO INC.	OS	Note 1			
7	CONSTELLATION ENGY COMMODITIES	OS	Note 1			
8	CORAL POWER LLC	OS	Note 1			
9	CREDIT SUISSE ENERGY	OS	Note 1			
10	DC ENERGY, LLC	OS	Note 1			
11	DELAWARE ELECTRIC MUNICIPAL CO	OS	Note 1			
12	DELMARVA POWER & LIGHT	OS	Note 1			
13	DP&L POWER SERVICES	OS	Note 1			
14	DTE ENERGY TRADING INC.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,597		98,356		98,356	1
15,220		1,008,425		1,008,425	2
-22		-905		-905	3
54,732		3,873,720		3,873,720	4
		-19,856		-19,856	5
-24,340		-1,389,208		-1,389,208	6
522,591		29,472,750		29,472,750	7
-6,629		-272,692		-272,692	8
43,352		2,174,693		2,174,693	9
		-48,441		-48,441	10
6,011		449,190		449,190	11
13,410		1,682,507		1,682,507	12
-27,814		-1,156,717		-1,156,717	13
-11,817		-468,704		-468,704	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	DUKE ENERGY CAROLINAS, LLC	OS	Note 1			
2	DUKE ENERGY INDIANA, INC.	OS	Note 1			
3	DUKE ENERGY KENTUCKY, INC.	OS	Note 1			
4	DUKE ENERGY TRADING	OS	Note 1			
5	DUKE POWER COMPANY	OS	Note 1			
6	DUQUESNE POWER, L.P.	OS	Note 1			
7	DYNEGY POWER MARKETING INC.	OS	Note 1			
8	EAGLE ENERGY PARTNER I, L.P.	OS	Note 1			
9	EAST KY POWER CO-OP POWER MKTG	OS	See Footnote			
10	EDISON MISSION MKTG & TRADING	OS	Note 1			
11	ENDURE ENERGY, LLC	OS	Note 1			
12	ENG MKTG, DIV OF AMERADA HESS	OS	Note 1			
13	ENTERGY POWER SERV	OS	Note 1			
14	EXELON GENERATION - POWER TEAM	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
4,432		226,470		226,470	1
		-16,739		-16,739	2
		271		271	3
-14,250		-140,100		-140,100	4
-2,976		-216,912		-216,912	5
51,116		2,937,201		2,937,201	6
		13,066		13,066	7
-5,245		-339,498		-339,498	8
38,543		2,053,482		2,053,482	9
-138,132		-8,616,309		-8,616,309	10
-84		-2,344		-2,344	11
33,939		2,680,208		2,680,208	12
8,864		362,054		362,054	13
-332,466		-17,709,931		-17,709,931	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	FIRSTENERGY TRADING SERVICES	OS	Note 1			
2	FPL ENERGY POWER MARKETINGINC	OS	Note 1			
3	GREAT RIVER ENERGY	OS	Note 1			
4	HARRISON RURAL ELECTRIFICATION	OS	Note 1			
5	HESS ENERGY TRADING COMPANY, L	OS	Note 1			
6	HETC	OS	Note 1			
7	HOOSIER POWER MARKET	OS	Note 1			
8	INDIANA MUNICIPAL POWER AGENCY	OS	Note 1			
9	INTEGRYS ENERGY SERVICES, INC	OS	Note 1			
10	INTERSTATE POWER & LIGHT CO	OS	Note 1			
11	J ARON & COMPANY	OS	Note 1			
12	JP MORGAN VENTURES ENERGY CORP	OS	Note 1			
13	KANSAS CITY POWER & LIGHT CO	OS	Note 1			
14	LEHMAN BROTHERS COMMODITY SVCS	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
28,966		1,815,923		1,815,923	1
-5,561		-428,385		-428,385	2
		268		268	3
6,046		294,688		294,688	4
		-22,333		-22,333	5
		-10		-10	6
16,139		905,815		905,815	7
21,104		1,259,087		1,259,087	8
129,088		7,385,252		7,385,252	9
		508		508	10
-12,127		-1,036,135		-1,036,135	11
10,901		551,549		551,549	12
579		53,891		53,891	13
-66,261		-4,182,832		-4,182,832	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Average Monthly CP Demand (f)
1	LG&E UTILITIES POWER SALES	OS	Note 1			
2	LOUIS DREYFUS ENERGY SERV LP	OS	Note 1			
3	MERRILL LYNCH COMMODITIES, INC	OS	Note 1			
4	MICHIGAN PUBLIC POWER AGENCY	OS	Note 1			
5	MID CONTINENT CORP.	OS	Note 1			
6	MIDAMERICAN ENERGY	OS	Note 1			
7	MIDWEST ISO	OS	Note 1			
8	MONONGAHELA POWER COMPANY	OS	Note 1			
9	MORGAN STANLEY CAPT.	OS	Note 1			
10	NC ELECTRIC MEMBERSHIP CORP.	OS	Note 1			
11	NIPSCO ENERGY MANAGEMENT	OS	Note 1			
12	NO CAROLINA MUNI PWR AGENCY #1	OS	Note 1			
13	NRG POWER MARKETING INC.	OS	Note 1			
14	NSP ENERGY MARKETING	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-759		-19,696		-19,696	1
		-1,962		-1,962	2
		359,188		359,188	3
5,090		316,023		316,023	4
		-5,826		-5,826	5
-3,476		-318,270		-318,270	6
-173,943		-9,965,335		-9,965,335	7
		24		24	8
37,115		3,322,097		3,322,097	9
8,407		22,779		22,779	10
21,254		1,462,201		1,462,201	11
-76		-4,328		-4,328	12
9,051		531,434		531,434	13
		-9,225		-9,225	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

1. Report all sales for resale (i.e., sales to purchasers other than ultimate consumers) transacted on a settlement basis other than power exchanges during the year. Do not report exchanges of electricity (i.e., transactions involving a balancing of debits and credits for energy, capacity, etc.) and any settlements for imbalanced exchanges on this schedule. Power exchanges must be reported on the Purchased Power schedule (Page 326-327).
2. Enter the name of the purchaser in column (a). Do note abbreviate or truncate the name or use acronyms. Explain in a footnote any ownership interest or affiliation the respondent has with the purchaser.
3. In column (b), enter a Statistical Classification Code based on the original contractual terms and conditions of the service as follows:

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

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

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

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

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

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	OCCIDENTAL POWER SERVICES, INC	OS	Note 1			
2	OLD DOMINION ELEC.	OS	Note 1			
3	OMEG	OS	Note 1			
4	OPPD ENERGY MARKETING	OS	Note 1			
5	ORMET PRIMARY ALUMINUM CORP	OS	Note 1			
6	OTTER TAIL POWER COMPANY	OS	Note 1			
7	OVEC POWER SCHEDULING	OS	Note 1			
8	PARIBAS	OS	Note 1			
9	PENNSYLVANIA POWER COMPANY	OS	Note 1			
10	PEPCO SERVICES INC.	OS	Note 1			
11	PJM INTERCONNECTION	OS	Note 1			
12	PP&L ENERGY PLUS CO.	OS	Note 1			
13	PPL ENERGY SUPPLY, LLC	OS	Note 1			
14	PROGRESS VENTURES, INC.	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
2,285		61,822		61,822	1
83,334		5,800,461		5,800,461	2
		2,187		2,187	3
		-1,893		-1,893	4
		19		19	5
-8,576		-464,339		-464,339	6
-84,162		-3,155,214		-3,155,214	7
		261,608		261,608	8
8,077		646,693		646,693	9
79,654		8,345,119		8,345,119	10
997,691		63,204,723		63,204,723	11
164,602		8,442,389		8,442,389	12
		7,958		7,958	13
		-1		-1	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	PSEG ENERGY RESOURCES & TRADE	OS	Note 1			
2	PUBLIC SERVICE CO OF OKLAHOMA	OS	Note 1			
3	RAINBOW ENERGY MARKETING	OS	Note 1			
4	REFCO INC.	OS	Note 1			
5	SEMPRA ENERGY SOLUTIONS, LLC	OS	Note 1			
6	SEMPRA ENERGY TRADING	OS	Note 1			
7	SHELL ENERGY N AMERICA (US) LP	OS	Note 1			
8	SOUTH CAROLINA ELECTRIC & GAS	OS	Note 1			
9	SOUTH TEXAS ELECTRIC COOP	OS	Note 1			
10	SOUTHEASTERN PUB SERV AUTH -VA	OS	Note 1			
11	SOUTHEN MARYLAND ELEC COOP INC	OS	Note 1			
12	SOUTHERN COMPANY	OS	Note 1			
13	SOUTHERN ELECTRIC INTL	OS	Note 1			
14	SOUTHERN ILLINOIS POWER CO-OP	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
-17,275		-1,733,166		-1,733,166	1
35,504		1,782,045		1,782,045	2
698		36,890		36,890	3
		272		272	4
42,191		2,992,135		2,992,135	5
5,349		37,349		37,349	6
-11,567		-585,417		-585,417	7
-814		-68,679		-68,679	8
		-1		-1	9
		-2,765		-2,765	10
12,424		1,213,412		1,213,412	11
-4,526		-430,036		-430,036	12
39,819		2,664,064		2,664,064	13
3,947		173,248		173,248	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations)	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	SOUTHWESTN ELECTRIC POWER	OS	Note 1			
2	STRATEGIC ENERGY LTD.	OS	Note 1			
3	TENASKA POWER SERVICES COMPANY	OS	Note 1			
4	THE BOROUGH OF PITCAIRN, PA	OS	Note 1			
5	THE ENERGY AUTHORITY	OS	Note 1			
6	THE POTOMAC EDISON COMPANY	OS	Note 1			
7	TOWN OF FRONT ROYAL	OS	Note 1			
8	TRANSALTA ENERGY MARKETING US	OS	Note 1			
9	TVA BULK POWER TRADING	OS	Note 1			
10	UBS AG, LONDON BRANCH	OS	Note 1			
11	UBS SECURITIES LLC	OS	Note 1			
12	UNION ELECTRIC COMPANY	OS	Note 1			
13	UNION POWER PARTNERS	OS	Note 1			
14	UNITED LIGHT & POWER COMPANY	OS	Note 1			
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

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

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
28,015		1,739,630		1,739,630	1
20,428		1,195,653		1,195,653	2
326		11,596		11,596	3
267		18,179		18,179	4
2,147		126,870		126,870	5
21,701		2,281,910		2,281,910	6
521		-143,516		-143,516	7
12		1,299		1,299	8
1,283		56,742		56,742	9
1,360		277,987		277,987	10
		-3,746,337		-3,746,337	11
-790		-159,654		-159,654	12
-54		-27,216		-27,216	13
		-38		-38	14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SALES FOR RESALE (Account 447)

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

Line No.	Name of Company or Public Authority (Footnote Affiliations) (a)	Statistical Classification (b)	FERC Rate Schedule or Tariff Number (c)	Average Monthly Billing Demand (MW) (d)	Actual Demand (MW) Average Monthly NCP Demand (e)	Actual Demand (MW) Average Monthly CP Demand (f)
1	VIRGINIA POWER MARKETING	OS	Note 1			
2	WABASH VALLEY POWER ASSN INC.	OS	Note 1			
3	WASHINGTON GAS ENERGY SERVICES	OS	Note 1			
4	WESTAR ENERGY INC.	OS	Note 1			
5	WISCONSIN POWER & LIGHT	OS	Note 1			
6	WOLVERINE POWER SUPPLY COOP	OS	Note 1			
7						
8						
9						
10						
11						
12						
13						
14						
	Subtotal RQ			0	0	0
	Subtotal non-RQ			0	0	0
	Total			**0**	**0**	**0**

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SALES FOR RESALE (Account 447) (Continued)

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

MegaWatt Hours Sold (g)	REVENUE Demand Charges ($) (h)	Energy Charges ($) (i)	Other Charges ($) (j)	Total ($) (h+i+j) (k)	Line No.
		-130		-130	1
-15,595		-1,157,808		-1,157,808	2
5,328		535,247		535,247	3
-983		-431,921		-431,921	4
40,183		2,339,735		2,339,735	5
		25,082		25,082	6
					7
					8
					9
					10
					11
					12
					13
					14
100,098	0	5,266,963	0	5,266,963	
4,530,663	3,806,269	198,954,184	0	202,760,453	
4,630,761	**3,806,269**	**204,221,147**	**0**	**208,027,416**	

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

Note 1: FERC Electric Tariff, Second Substitute Volume No. 5

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

The termination date of this contract is May 31, 2012.

Schedule Page: 310 Line No.: 8 Column: b

The termination date of the contract is December 31, 2010. However the contract could be cancelled or modified during the contract term by mutual agreement.

Schedule Page: 310 Line No.: 12 Column: a

Affiliated Company

Schedule Page: 310 Line No.: 13 Column: a

Affiliated Company - transactions related to the System Integration Agreement.

Schedule Page: 310.4 Line No.: 9 Column: c

KYPO FERC ELECTRIC TARIFF ORIGINAL VOL. NO. 2, SA NO. 79

Schedule Page: 310.8 Line No.: 2 Column: a

Affiliated Company

Schedule Page: 310.9 Line No.: 1 Column: a

Affiliated Company

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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	/ /	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
1	1. POWER PRODUCTION EXPENSES		
2	A. Steam Power Generation		
3	Operation		
4	(500) Operation Supervision and Engineering	5,473,552	4,442,636
5	(501) Fuel	166,915,229	144,114,703
6	(502) Steam Expenses	4,211,285	3,060,647
7	(503) Steam from Other Sources		
8	(Less) (504) Steam Transferred-Cr.		
9	(505) Electric Expenses	68,594	63,982
10	(506) Miscellaneous Steam Power Expenses	6,029,249	7,904,323
11	(507) Rents		
12	(509) Allowances	1,836,777	2,067,653
13	TOTAL Operation (Enter Total of Lines 4 thru 12)	184,534,686	161,653,944
14	Maintenance		
15	(510) Maintenance Supervision and Engineering	612,731	645,604
16	(511) Maintenance of Structures	643,319	632,135
17	(512) Maintenance of Boiler Plant	15,764,360	10,067,795
18	(513) Maintenance of Electric Plant	6,904,381	2,020,517
19	(514) Maintenance of Miscellaneous Steam Plant	709,950	569,995
20	TOTAL Maintenance (Enter Total of Lines 15 thru 19)	24,634,741	13,936,046
21	TOTAL Power Production Expenses-Steam Power (Entr Tot lines 13 & 20)	209,169,427	175,589,990
22	B. Nuclear Power Generation		
23	Operation		
24	(517) Operation Supervision and Engineering		
25	(518) Fuel		
26	(519) Coolants and Water		
27	(520) Steam Expenses		
28	(521) Steam from Other Sources		
29	(Less) (522) Steam Transferred-Cr.		
30	(523) Electric Expenses		
31	(524) Miscellaneous Nuclear Power Expenses		
32	(525) Rents		
33	TOTAL Operation (Enter Total of lines 24 thru 32)		
34	Maintenance		
35	(528) Maintenance Supervision and Engineering		
36	(529) Maintenance of Structures		
37	(530) Maintenance of Reactor Plant Equipment		
38	(531) Maintenance of Electric Plant		
39	(532) Maintenance of Miscellaneous Nuclear Plant		
40	TOTAL Maintenance (Enter Total of lines 35 thru 39)		
41	TOTAL Power Production Expenses-Nuc. Power (Entr tot lines 33 & 40)		
42	C. Hydraulic Power Generation		
43	Operation		
44	(535) Operation Supervision and Engineering		
45	(536) Water for Power		
46	(537) Hydraulic Expenses		
47	(538) Electric Expenses		
48	(539) Miscellaneous Hydraulic Power Generation Expenses		
49	(540) Rents		
50	TOTAL Operation (Enter Total of Lines 44 thru 49)		
51	C. Hydraulic Power Generation (Continued)		
52	Maintenance		
53	(541) Mainentance Supervision and Engineering		
54	(542) Maintenance of Structures		
55	(543) Maintenance of Reservoirs, Dams, and Waterways		
56	(544) Maintenance of Electric Plant		
57	(545) Maintenance of Miscellaneous Hydraulic Plant		
58	TOTAL Maintenance (Enter Total of lines 53 thru 57)		
59	TOTAL Power Production Expenses-Hydraulic Power (tot of lines 50 & 58)		

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
60	D. Other Power Generation		
61	Operation		
62	(546) Operation Supervision and Engineering		
63	(547) Fuel		
64	(548) Generation Expenses		
65	(549) Miscellaneous Other Power Generation Expenses		
66	(550) Rents		
67	TOTAL Operation (Enter Total of lines 62 thru 66)		
68	Maintenance		
69	(551) Maintenance Supervision and Engineering		
70	(552) Maintenance of Structures		
71	(553) Maintenance of Generating and Electric Plant		
72	(554) Maintenance of Miscellaneous Other Power Generation Plant		
73	TOTAL Maintenance (Enter Total of lines 69 thru 72)		
74	TOTAL Power Production Expenses-Other Power (Enter Tot of 67 & 73)		
75	E. Other Power Supply Expenses		
76	(555) Purchased Power	287,187,513	224,842,109
77	(556) System Control and Load Dispatching	404,887	367,496
78	(557) Other Expenses	2,546,525	2,820,526
79	TOTAL Other Power Supply Exp (Enter Total of lines 76 thru 78)	290,138,925	228,030,131
80	TOTAL Power Production Expenses (Total of lines 21, 41, 59, 74 & 79)	499,308,352	403,620,121
81	2. TRANSMISSION EXPENSES		
82	Operation		
83	(560) Operation Supervision and Engineering	564,839	398,808
84	(561) Load Dispatching		
85	(561.1) Load Dispatch-Reliability	10,813	6,132
86	(561.2) Load Dispatch-Monitor and Operate Transmission System	804,673	749,163
87	(561.3) Load Dispatch-Transmission Service and Scheduling	227	
88	(561.4) Scheduling, System Control and Dispatch Services	1,181,168	1,772,573
89	(561.5) Reliability, Planning and Standards Development	16,926	8,489
90	(561.6) Transmission Service Studies		
91	(561.7) Generation Interconnection Studies		
92	(561.8) Reliability, Planning and Standards Development Services	205,033	242,204
93	(562) Station Expenses	199,410	177,271
94	(563) Overhead Lines Expenses	296,748	423,147
95	(564) Underground Lines Expenses		
96	(565) Transmission of Electricity by Others	-1,531,617	-679,779
97	(566) Miscellaneous Transmission Expenses	1,210,553	808,107
98	(567) Rents	2,044	1,847
99	TOTAL Operation (Enter Total of lines 83 thru 98)	2,960,817	3,907,962
100	Maintenance		
101	(568) Maintenance Supervision and Engineering	163,996	161,707
102	(569) Maintenance of Structures	19,196	53,407
103	(569.1) Maintenance of Computer Hardware	40,549	35,347
104	(569.2) Maintenance of Computer Software	245,494	136,480
105	(569.3) Maintenance of Communication Equipment	213,377	219,102
106	(569.4) Maintenance of Miscellaneous Regional Transmission Plant		
107	(570) Maintenance of Station Equipment	798,670	983,263
108	(571) Maintenance of Overhead Lines	2,292,773	2,812,362
109	(572) Maintenance of Underground Lines	7	979
110	(573) Maintenance of Miscellaneous Transmission Plant	3,472	5,882
111	TOTAL Maintenance (Total of lines 101 thru 110)	3,777,534	4,408,529
112	TOTAL Transmission Expenses (Total of lines 99 and 111)	6,738,351	8,316,491

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
113	3. REGIONAL MARKET EXPENSES		
114	Operation		
115	(575.1) Operation Supervision		
116	(575.2) Day-Ahead and Real-Time Market Facilitation		
117	(575.3) Transmission Rights Market Facilitation		
118	(575.4) Capacity Market Facilitation		
119	(575.5) Ancillary Services Market Facilitation		
120	(575.6) Market Monitoring and Compliance		
121	(575.7) Market Facilitation, Monitoring and Compliance Services	1,026,386	1,418,698
122	(575.8) Rents		
123	Total Operation (Lines 115 thru 122)	1,026,386	1,418,698
124	Maintenance		
125	(576.1) Maintenance of Structures and Improvements		
126	(576.2) Maintenance of Computer Hardware		
127	(576.3) Maintenance of Computer Software		
128	(576.4) Maintenance of Communication Equipment		
129	(576.5) Maintenance of Miscellaneous Market Operation Plant		
130	Total Maintenance (Lines 125 thru 129)		
131	TOTAL Regional Transmission and Market Op Expns (Total 123 and 130)	1,026,386	1,418,698
132	4. DISTRIBUTION EXPENSES		
133	Operation		
134	(580) Operation Supervision and Engineering	1,055,735	1,009,894
135	(581) Load Dispatching	5,088	12,279
136	(582) Station Expenses	240,605	226,308
137	(583) Overhead Line Expenses	685,565	202,474
138	(584) Underground Line Expenses	81,073	100,283
139	(585) Street Lighting and Signal System Expenses	64,845	91,987
140	(586) Meter Expenses	553,552	260,409
141	(587) Customer Installations Expenses	262,870	375,546
142	(588) Miscellaneous Expenses	4,117,800	3,643,324
143	(589) Rents	1,442,089	1,550,093
144	TOTAL Operation (Enter Total of lines 134 thru 143)	8,509,222	7,472,597
145	Maintenance		
146	(590) Maintenance Supervision and Engineering	5,936	8,802
147	(591) Maintenance of Structures	9,815	33,186
148	(592) Maintenance of Station Equipment	793,557	755,514
149	(593) Maintenance of Overhead Lines	15,751,488	14,439,972
150	(594) Maintenance of Underground Lines	236,613	303,307
151	(595) Maintenance of Line Transformers	555,405	772,126
152	(596) Maintenance of Street Lighting and Signal Systems	53,425	64,928
153	(597) Maintenance of Meters	158,121	131,766
154	(598) Maintenance of Miscellaneous Distribution Plant	528,700	585,361
155	TOTAL Maintenance (Total of lines 146 thru 154)	18,093,060	17,094,962
156	TOTAL Distribution Expenses (Total of lines 144 and 155)	26,602,282	24,567,559
157	5. CUSTOMER ACCOUNTS EXPENSES		
158	Operation		
159	(901) Supervision	401,085	429,649
160	(902) Meter Reading Expenses	993,970	1,073,679
161	(903) Customer Records and Collection Expenses	5,948,209	6,205,360
162	(904) Uncollectible Accounts	37,059	-104
163	(905) Miscellaneous Customer Accounts Expenses	4,229	2,888
164	TOTAL Customer Accounts Expenses (Total of lines 159 thru 163)	7,384,552	7,711,472

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

ELECTRIC OPERATION AND MAINTENANCE EXPENSES (Continued)

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

Line No.	Account (a)	Amount for Current Year (b)	Amount for Previous Year (c)
165	6. CUSTOMER SERVICE AND INFORMATIONAL EXPENSES		
166	Operation		
167	(907) Supervision	223,464	277,716
168	(908) Customer Assistance Expenses	1,181,879	1,353,531
169	(909) Informational and Instructional Expenses	210,909	270,404
170	(910) Miscellaneous Customer Service and Informational Expenses	53,979	110,908
171	TOTAL Customer Service and Information Expenses (Total 167 thru 170)	1,670,231	2,012,559
172	7. SALES EXPENSES		
173	Operation		
174	(911) Supervision		23
175	(912) Demonstrating and Selling Expenses		
176	(913) Advertising Expenses		
177	(916) Miscellaneous Sales Expenses		
178	TOTAL Sales Expenses (Enter Total of lines 174 thru 177)		23
179	8. ADMINISTRATIVE AND GENERAL EXPENSES		
180	Operation		
181	(920) Administrative and General Salaries	5,537,843	6,832,888
182	(921) Office Supplies and Expenses	845,004	676,385
183	(Less) (922) Administrative Expenses Transferred-Credit	1,110,676	986,011
184	(923) Outside Services Employed	5,885,492	5,789,830
185	(924) Property Insurance	367,523	501,344
186	(925) Injuries and Damages	1,370,196	1,393,492
187	(926) Employee Pensions and Benefits	4,765,373	4,466,809
188	(927) Franchise Requirements	183,096	168,750
189	(928) Regulatory Commission Expenses	2,026	1,106
190	(929) (Less) Duplicate Charges-Cr.		
191	(930.1) General Advertising Expenses	154,799	117,976
192	(930.2) Miscellaneous General Expenses	2,210,676	603,159
193	(931) Rents	655,351	678,586
194	TOTAL Operation (Enter Total of lines 181 thru 193)	20,866,703	20,244,314
195	Maintenance		
196	(935) Maintenance of General Plant	1,415,115	1,529,673
197	TOTAL Administrative & General Expenses (Total of lines 194 and 196)	22,281,818	21,773,987
198	TOTAL Elec Op and Maint Expns (Total 80,112,131,156,164,171,178,197)	565,011,972	469,420,910

Schedule Page: 320 Line No.: 86 Column: b

Any amounts for 561.0 for both current and prior period have been reclassified to 561.2.

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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	/ /	End of 2008/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 1			
2	National Power Cooperative Inc	LF	Note 1			
3	American Electric Power Service Corp	OS	APCO 20			
4	American Electric Power Service Corp	OS	Note 1			
5	Allegheny Energy Supply Co LLC	OS	Note 1			
6	Ameren Energy Marketing	OS	Note 1			
7	Barclays Bank PLC	OS	Note 1			
8	BP Amoco	OS	Note 1			
9	Buckeye Rural Electric Admin	OS	Note 1			
10	Citigroup Energy Inc	OS	Note 1			
11	Commonwealth Edison Co Auctio2	OS	Note 1			
12	Constellation Energy Commodities	OS	Note 1			
13	Credit Suisse Energy	OS	Note 1			
14	DTE Energy Trading Inc	OS	Note 1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
2,985,358			40,162,411	66,094,025		106,256,436	1
2,496			26,973	361,325		388,298	2
2,746,448				127,668,597		127,668,597	3
				512,890		512,890	4
4,171				210,858		210,858	5
				8,268		8,268	6
				-57,003		-57,003	7
				46,584		46,584	8
				-181,080		-181,080	9
				5,373		5,373	10
				7,703		7,703	11
-1,263				302,545		302,545	12
				80,866		80,866	13
				59,222		59,222	14
6,419,316			40,189,384	246,998,129		287,187,513	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	Edison Mission Marketing & Trading	OS	Note 1			
2	Exelon Generation-Power Team	OS	Note 1			
3	Firstenergy Trading Services	OS	Note 1			
4	FPL Energy Power Marketing Inc	OS	Note 1			
5	Great River Energy	OS	Note 1			
6	J Aron & Company	OS	Note 1			
7	JP Morgan Ventures Energy Corp	OS	Note 1			
8	Lehman Brothers Commodity Svcs	OS	Note 1			
9	Merrill Lynch Commodities, Inc	OS	Note 1			
10	Midwest ISO	OS	Note 1			
11	Morgan Stanley Capt	OS	Note 1			
12	PJM Environmental Info Sys Inc	OS	Note 1			
13	PJM Interconnection	OS	Note 1			
14	PSEG Energy Resources & Trade	OS	Note 1			
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
				6,494		6,494	1
				273,036		273,036	2
				49,302		49,302	3
				7,069		7,069	4
				14,738		14,738	5
				-82,717		-82,717	6
				347		347	7
				54,394		54,394	8
				19,294		19,294	9
8,358				458,639		458,639	10
7,422				396,173		396,173	11
				1,042		1,042	12
587,316				49,002,057		49,002,057	13
				833		833	14
6,419,316			40,189,384	246,998,129		287,187,513	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	Public Service Company of Oklahoma	OS	Note 1			
2	Sempra Energy Solutions, LLC	OS	Note 1			
3	Sempra Energy Trading	OS	Note 1			
4	Southeastern Pub Serv Auth-VA	OS	Note 1			
5	Southwestern Electric Power Comp	OS	Note 1			
6	UBS AG, London Branch	OS	Note 1			
7	UBS Securities LLC	OS	Note 1			
8	Union Electric Company	OS	Note 1			
9	Wabash Valley Power Assn Inc	OS	Note 1			
10	Wisconsin Public Service	OS	Note 1			
11	Miscellaneous MWH Adjustment		Note 1			
12						
13						
14						
	Total					

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

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

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

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

MegaWatt Hours Purchased (g)	POWER EXCHANGES		COST/SETTLEMENT OF POWER				Line No.
	MegaWatt Hours Received (h)	MegaWatt Hours Delivered (i)	Demand Charges ($) (j)	Energy Charges ($) (k)	Other Charges ($) (l)	Total (j+k+l) of Settlement ($) (m)	
4,870				290,974		290,974	1
				-158,314		-158,314	2
				-8,400		-8,400	3
6,441				443,570		443,570	4
2,947				163,227		163,227	5
				811		811	6
				888,170		888,170	7
				25,524		25,524	8
				16,341		16,341	9
				15,352		15,352	10
64,752							11
							12
							13
							14
6,419,316			40,189,384	246,998,129		287,187,513	

Name of Respondent	This Report is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) X An Original (2) _ A Resubmission	/ /	2008/Q4

FOOTNOTE DATA

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

An AEP affiliate.

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

The termination date of the contract is September 30, 2032.

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

Note 1: AEP Power Sales Tariff - AEP Companies FERC Electric Tariff Original Volume 2.

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

The Respondent, Indiana Michigan Power Company, Ohio Power Company, Columbus Southern Power Company and Appalachian Power Company are associated companies and members of the American Electric Power System Power Pool, whose electric facilities are interconnected at a number of points and are operated in a fully coordinated manner on a system pool basis.

APCO - Appalachian Power Company
OPCO - Ohio Power Company
IMPCO - Indiana Michigan Power Company
KPCO - Kentucky Power Company
CSPCO - Columbus Southern Power Company

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

Statistical classification "OS" included non-firm hourly, daily and weekly purchases that the supplier may cancel, if necessary, with little notice.

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

Receipts of power from the members of the AEP System Power Pool, governed by the terms of the interconnection agreement dated July 6, 1951, as amended.

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

Affiliated Company - transactions related to the System Integration Agreement.

Schedule Page: 326.2 Line No.: 1 Column: a

An AEP affiliate.

Schedule Page: 326.2 Line No.: 5 Column: a

An AEP affiliate.

Schedule Page: 326.2 Line No.: 11 Column: g

BOOKOUT/OPTIONS	22,492
MLR PURCHASES	(39)
PJM NON-ECR	(16,541)
SPOT ENERGY (PJM)	145
POOL ADJUSTMENT	60,609
BY-THRU	(1,914)
TOTAL MISC MWH ADJUSTMENTS	64,752

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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	/ /	End of 2008/Q4

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

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

Line No.	Payment By (Company of Public Authority) (Footnote Affiliation) (a)	Energy Received From (Company of Public Authority) (Footnote Affiliation) (b)	Energy Delivered To (Company of Public Authority) (Footnote Affiliation) (c)	Statistical Classification (d)
1	PJM Network Integration Transmission	Various	Various	FNO
2	PJM Point to Point Transmission Service	Various	Various	OLF
3	PJM Transmission Owner Administrative	Various	Various	OS
4	PJM Expansion Cost Recovery	Various	Various	OS
5	RTO Formation Cost Recovery	Various	Various	OS
6	East Kentucky Power Cooperative	Various	Various	OLF
7				
8				
9				
10				
11				
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32				
33				
34				
	TOTAL			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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
FERC #14	Various	Various		46,648	46,648	6
						7
						8
						9
						10
						11
						12
						13
						14
						15
						16
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						27
						28
						29
						30
						31
						32
						33
						34
			0	**46,648**	**46,648**	

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

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

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

REVENUE FROM TRANSMISSION OF ELECTRICITY FOR OTHERS

Demand Charges ($) (k)	Energy Charges ($) (l)	(Other Charges) ($) (m)	Total Revenues ($) (k+l+m) (n)	Line No.
3,578,285			3,578,285	1
1,226,389			1,226,389	2
		209,148	209,148	3
		78,516	78,516	4
		14,701	14,701	5
		69,972	69,972	6
				7
				8
				9
				10
				11
				12
				13
				14
				15
				16
				17
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				30
				31
				32
				33
				34
4,804,674	**0**	**372,337**	**5,177,011**	

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

Effective Oct 1, 2004 the administration of the transmission tariff was turned over to the PJM. PJM does not provide any detail except for the total revenue by the major classes listed.

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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		EXPENSES FOR TRANSMISSION OF ELECTRICITY BY OTHERS			
			Magawatt-hours Received (c)	Magawatt-hours Delivered (d)	Demand Charges ($) (e)	Energy Charges ($) (f)	Other Charges ($) (g)	Total Cost of Transmission ($) (h)
1	Concurrent Energy							
2	East KY Power Coop	LFP	79,303	79,303			118,955	118,955
3								
4	AEP Sys Trans Agreement	FNS					-2,022,570	-2,022,570
5								
6	PJM	OS					371,998	371,998
7								
8								
9								
10								
11								
12								
13								
14								
15								
16								
	TOTAL		79,303	79,303			-1,531,617	-1,531,617

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

The Respondent, Appalachian Power Company, Columbus Southern Power Company, Indiana & Michigan Power Company and Ohio Power Company are associated companies and are parties to the Transmission Agreement dated April 1, 1984, as amended. Pursuant to the terms of the Transmission Agreement, American Electric Power Service Corporation serves as agent and the parties pool their investments in high voltage transmission facilities (138kv and above) and share the cost of ownership in proportion to the respective member's load ratio. As such, there is no transfer of energy and some parties receive credits which are recorded in account 565.

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

Trasmission Enhancement Charges and Credits (PJM OATT Schedule 12)

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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

MISCELLANEOUS GENERAL EXPENSES (Account 930.2) (ELECTRIC)

Line No.	Description (a)	Amount (b)
1	Industry Association Dues	89,006
2	Nuclear Power Research Expenses	
3	Other Experimental and General Research Expenses	6,120
4	Pub & Dist Info to Stkhldrs...expn servicing outstanding Securities	11,250
5	Oth Expn >=5,000 show purpose, recipient, amount. Group if < $5,000	
6	Associated Business Development	1,940,694
7	AEP Utility Funding, LLC	11,494
8	AEP Service Corporation Billings	114,252
9	Aramsco, Inc.-Pandemic Preparedness Program	-6,578
10	Intercompany Billings	-22,845
11	PGA Ryder Cup Tournament	3,357
12	Relocation Expense	44,794
13	WYMT TV - Presentation	6,800
14	YMCA Sponsorship 'East Kentucky Miners'	5,000
15	Misc Items <5,000	7,332
16		
17		
18		
19		
20		
21		
22		
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24		
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43		
44		
45		
46	TOTAL	2,210,676

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Account 403, 404, 405)
(Except amortization of aquisition adjustments)

1. Report in section A for the year the amounts for : (b) Depreciation Expense (Account 403; (c) Depreciation Expense for Asset Retirement Costs (Account 403.1; (d) Amortization of Limited-Term Electric Plant (Account 404); and (e) Amortization of Other Electric Plant (Account 405).
2. Report in Section 8 the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute charges and whether any changes have been made in the basis or rates used from the preceding report year.
3. Report all available information called for in Section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.
Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of Section C the type of plant included in any sub-account used.
In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional Classifications and showing composite total. Indicate at the bottom of section C the manner in which column balances are obtained. If average balances, state the method of averaging used.
For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification Listed in column (a). If plant mortality studies are prepared to assist in estimating average service Lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant. If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.
4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Depreciation Expense for Asset Retirement Costs (Account 403.1) (c)	Amortization of Limited Term Electric Plant (Account 404) (d)	Amortization of Other Electric Plant (Acc 405) (e)	Total (f)
1	Intangible Plant			3,214,644		3,214,644
2	Steam Production Plant	17,734,431		552,361		18,286,792
3	Nuclear Production Plant					
4	Hydraulic Production Plant-Conventional					
5	Hydraulic Production Plant-Pumped Storage					
6	Other Production Plant					
7	Transmission Plant	7,010,560				7,010,560
8	Distribution Plant	18,041,242				18,041,242
9	Regional Transmission and Market Operation					
10	General Plant	768,780		97,017		865,797
11	Common Plant-Electric					
12	TOTAL	43,555,013		3,864,022		47,419,035

B. Basis for Amortization Charges

Section A Line 1 Column D represents amortization of franchises over the life of the franchise ($539) and amortization of capitalized software development costs over a 5 year life ($3,214,105)

Section A Line 2 Column D represents amortization of Selective Catalytic Reduction catalyst equipment over a useful life range defined as:

SCR Catalyst Layer 1 (15 years) = ($217,405)
SCR Catalyst Layer 2 (19 years) = ($171,697)
SCR Catalyst Layer 3 (10 years) = ($163,259)

TOTAL = ($552,361)

Section A Line 10 Column D represents amortization of Hazard Building lease over the estimated useful life of the lease ($97,017)

Name of Respondent	This Report Is:	Date of Report (Mo; Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	475,041					
13	Transmission Plant	424,427					
14	Distribution Plant	522,994					
15	General Plant	31,140					
16	DEPRECIABLE SUM	1,453,602					
17							
18							
19							
20							
21							
22							
23							
24							
25							
26							
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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	(Mo, Da, Yr) / /	2008/Q4

FOOTNOTE DATA

Schedule Page: 336 Line No.: 16 Column: b

(1) The depreciable plant base is the November 30, 2008 total company depreciable plant.

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Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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	Miscellaneous Items		2,026	2,026	
2					
3					
4					
5					
6					
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
27					
28					
29					
30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL		2,026	2,026	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

REGULATORY COMMISSION EXPENSES (Continued)

3. Show in column (k) any expenses incurred in prior years which are being amortized. List in column (a) the period of amortization.
4. List in column (f), (g), and (h) expenses incurred during year which were charged currently to income, plant, or other accounts.
5. Minor items (less than $25,000) may be grouped.

EXPENSES INCURRED DURING YEAR				AMORTIZED DURING YEAR			
CURRENTLY CHARGED TO							
Department (f)	Account No. (g)	Amount (h)	Deferred to Account 182.3 (i)	Contra Account (j)	Amount (k)	Deferred in Account 182.3 End of Year (l)	Line No.
	928	2,026					1
							2
							3
							4
							5
							6
							7
							8
							9
							10
							11
							12
							13
							14
							15
							16
							17
							18
							19
							20
							21
							22
							23
							24
							25
							26
							27
							28
							29
							30
							31
							32
							33
							34
							35
							36
							37
							38
							39
							40
							41
							42
							43
							44
							45
		2,026					46

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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 $5,000.)
- (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) Generation	1 item under $5,000
2		
3	A (1) b: Generation: Fossil-Fuel Steam	Coal Utilization Research Coun
4		4 items under $5,000
5		
6	A (1) e: Generation: Unconventional	2007 DER Program Management
7		Rolls-Royce 1MW SOFC Test & Eval
8		2 items under $5,000
9		
10	A(2): Transmission	7 items under $5,000
11		
12	A(2)a: Transmission: Overhead	2 items under $5,000
13		
14	A(3): Distribution	2 items under $5,000
15		
16	A(4): Regional Transmission & Market Operation	1 item under $5,000
17		
18	A(5): Environment (other than equipment)	Environmental Science & Controls ProgMgmt
19		Oxy-Coal Feasibility Study
20		7 items under $5,000
21		
22	A(6): Other	AMI Test Bed Development
23		Corporate Technology Prog Mgmt
24		DTC Walnut Maintenance
25		Grid of the Future Test Bed
26		Line Equip. Investigation Tools
27		Rampressor Feasibility Study
28		4 items under $5,000
29		
30		
31		
32	A(7) Total Cost Incurred Internally	
33		
34		
35		
36		
37		

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 $5,000 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 $5,000 by classifications and indicate the number of items grouped. Under Other, (A (6) and B (4)) classify items by type of R, D & D activity.
4. Show in column (e) the account number charged with expenses during the year or the account to which amounts were capitalized during the year, listing Account 107, Construction Work in Progress, first. Show in column (f) the amounts related to the account charged in column (e)
5. Show in column (g) the total unamortized accumulating of costs of projects. This total must equal the balance in Account 188, Research, Development, and Demonstration Expenditures, Outstanding at the end of the year.
6. If costs have not been segregated for R, D &D activities or projects, submit estimates for columns (c), (d), and (f) with such amounts identified by "Est."
7. Report separately research and related testing facilities operated by the respondent.

Costs Incurred Internally Current Year (c)	Costs Incurred Externally Current Year (d)	AMOUNTS CHARGED IN CURRENT YEAR Account (e)	AMOUNTS CHARGED IN CURRENT YEAR Amount (f)	Unamortized Accumulation (g)	Line No.
25		506	25		1
					2
9,136		506	9,136		3
6,290		506	6,290		4
					5
33,484		588	33,484		6
9,640		588	9,640		7
43		506,588	43		8
					9
11,021		566	11,021		10
					11
364		566	364		12
					13
5,194		566, 588	5,194		14
					15
209		588	209		16
					17
5,016		506	5,016		18
35,225		506	35,225		19
7,673		506	7,673		20
					21
14,977		588	14,977		22
15,456		Various	15,456		23
5,859		566,588	5,859		24
29,585		588	29,585		25
10,396		588	10,396		26
14,487		506	14,487		27
2,998		Various	2,998		28
					29
					30
					31
217,078			217,078		32
					33
					34
					35
					36

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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 $5,000.)
(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	B(1): Research Support to the electric	
2	Research Council or the Electric Power	EPRI Annual Portfolio
3	Research Inst	Dist. EPRI Annual Research Portfolio
4		EPRI Demo - Energy Efficiency
5		EPRI Demo - IGCC with CO2 Capture & Storage
6		EPRI Demo - Ion Transport Membrane Oxygen
7		EPRI Demo - Post Combustion CO2 Capture & Strge
8		EPRI Demo - Smart Grid
9		EPRI Environmental Controls
10		EPRI Environmental Science
11		Green Circuits
12		31 items under $5,000
13		
14		
15	B(4): Research Support to Others	Future Gen
16		8 items under $5,000
17		
18	B(5) Total Cost Incurred Externaly	
19		
20		
21		
22		
23		
24		
25		
26		
27		
28		
29		
30		
31		
32		
33		
34		
35		
36		
37		

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

RESEARCH, DEVELOPMENT, AND DEMONSTRATION ACTIVITIES (Continued)

(2) Research Support to Edison Electric Institute
(3) Research Support to Nuclear Power Groups
(4) Research Support to Others (Classify)
(5) Total Cost Incurred

3. Include in column (c) all R, D & D items performed internally and in column (d) those items performed outside the company costing $5,000 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 $5,000 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.
					37
					38
					1
	60,548	506,566	60,548		2
	61,974	588	61,974		3
	6,460	588	6,460		4
	40,449	506	40,449		5
	13,483	506	13,483		6
	33,708	506	33,708		7
	7,614	588	7,614		8
	44,399	506	44,399		9
	198,550	506	198,550		10
	5,589	588	5,589		11
	27,156	506,566	27,156		12
					13
					14
	22,858	506	22,858		15
	18,307	Various	18,307		16
					17
	541,095		541,095		18
					19
					20
					21
					22
					23
					24
					25
					26
					27
					28
					29
					30
					31
					32
					33
					34

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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	6,404,014		
4	Transmission	604,872		
5	Regional Market			
6	Distribution	2,690,850		
7	Customer Accounts	1,602,234		
8	Customer Service and Informational	379,635		
9	Sales			
10	Administrative and General	1,015,949		
11	TOTAL Operation (Enter Total of lines 3 thru 10)	12,697,554		
12	Maintenance			
13	Production	4,701,973		
14	Transmission	1,018,185		
15	Regional Market			
16	Distribution	5,179,410		
17	Administrative and General	751,428		
18	TOTAL Maintenance (Total of lines 13 thru 17)	11,650,996		
19	Total Operation and Maintenance			
20	Production (Enter Total of lines 3 and 13)	11,105,987		
21	Transmission (Enter Total of lines 4 and 14)	1,623,057		
22	Regional Market (Enter Total of Lines 5 and 15)			
23	Distribution (Enter Total of lines 6 and 16)	7,870,260		
24	Customer Accounts (Transcribe from line 7)	1,602,234		
25	Customer Service and Informational (Transcribe from line 8)	379,635		
26	Sales (Transcribe from line 9)			
27	Administrative and General (Enter Total of lines 10 and 17)	1,767,377		
28	TOTAL Oper. and Maint. (Total of lines 20 thru 27)	24,348,550	1,381,165	25,729,715
29	Gas			
30	Operation			
31	Production-Manufactured Gas			
32	Production-Nat. Gas (Including Expl. and Dev.)			
33	Other Gas Supply			
34	Storage, LNG Terminaling and Processing			
35	Transmission			
36	Distribution			
37	Customer Accounts			
38	Customer Service and Informational			
39	Sales			
40	Administrative and General			
41	TOTAL Operation (Enter Total of lines 31 thru 40)			
42	Maintenance			
43	Production-Manufactured Gas			
44	Production-Natural Gas (Including Exploration and Development)			
45	Other Gas Supply			
46	Storage, LNG Terminaling and Processing			
47	Transmission			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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)	24,348,550	1,381,165	25,729,715
66	Utility Plant			
67	Construction (By Utility Departments)			
68	Electric Plant	11,540,830	654,650	12,195,480
69	Gas Plant			
70	Other (provide details in footnote):			
71	TOTAL Construction (Total of lines 68 thru 70)	11,540,830	654,650	12,195,480
72	Plant Removal (By Utility Departments)			
73	Electric Plant	2,356,384	133,665	2,490,049
74	Gas Plant			
75	Other (provide details in footnote):			
76	TOTAL Plant Removal (Total of lines 73 thru 75)	2,356,384	133,665	2,490,049
77	Other Accounts (Specify, provide details in footnote):			
78	152 - Fuel Stock Undistributed	1,138,627		1,138,627
79	163 - Stores Expense Undistributed	1,387,850	-1,387,850	
80	184 - Clearing Accounts	781,630	-781,630	
81	185 - ODD Temporary Facilities	42,170		42,170
82	186 - Misc Deferred Debits	223,881		223,881
83	188 - Research & Development	-2,120		-2,120
84	426 - Donations	32,055		32,055
85				
86				
87				
88				
89				
90				
91				
92				
93				
94				
95	TOTAL Other Accounts	3,604,093	-2,169,480	1,434,613
96	TOTAL SALARIES AND WAGES	41,849,857		41,849,857

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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	/ /	End of 2008/Q4

AMOUNTS INCLUDED IN ISO/RTO SETTLEMENT STATEMENTS

1. The respondent shall report below the details called for concerning amounts it recorded in Account 555, Purchase Power, and Account 447, Sales for Resale, for items shown on ISO/RTO Settlement Statements. Transactions should be separately netted for each ISO/RTO administered energy market for purposes of determining whether an entity is a net seller or purchaser in a given hour. Net megawatt hours are to be used as the basis for determining whether a net purchase or sale has occurred. In each monthly reporting period, the hourly sale and purchase net amounts are to be aggregated and separately reported in Account 447, Sales for Resale, or Account 555, Purchased Power, respectively.

Line No.	Description of Item(s) (a)	Balance at End of Quarter 1 (b)	Balance at End of Quarter 2 (c)	Balance at End of Quarter 3 (d)	Balance at End of Year (e)
1	Energy				
2	Net Purchases (Account 555)				8,110,203
3	Net Sales (Account 447)				(7,885,618)
4	Transmission Rights				(2,261,845)
5	Ancillary Services				849,405
6	Other Items (list separately)				
7	Congestion				1,959,439
8	Operating Reserves				(253,566)
9	Transmission Purchase Expense				4,820
10	Transmission Losses				2,222,745
11	Meter Corrections				37,078
12	Inadvertent				9,886
13	Miscellaneous				513,381
14					
15					
16					
17					
18					
19					
20					
21					
22					
23					
24					
25					
26					
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30					
31					
32					
33					
34					
35					
36					
37					
38					
39					
40					
41					
42					
43					
44					
45					
46	TOTAL				3,305,928

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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		NA		262,769	1019	26,776
2	Reactive Supply and Voltage		NA			NA	
3	Regulation and Frequency Response		NA			NA	
4	Energy Imbalance		NA			NA	
5	Operating Reserve - Spinning		NA			NA	
6	Operating Reserve - Supplement		NA			NA	
7	Other		NA			NA	
8	Total (Lines 1 thru 7)				262,769		26,776

Schedule Page: 398 Line No.: 1 Column: e

Represents Company's MLR share of AEP System revenues, Column G, divided by Column F.

Schedule Page: 398 Line No.: 1 Column: f

The unit of measure for all ancillary services except energy imbalance.

Schedule Page: 398 Line No.: 1 Column: g

Represents company's member load ratio (MLR) of AEP System's ancillary 1 service revenues for grandfathered agreements.

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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	/ /	2008/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	/ /	End of 2008/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)	7,241,902
3	Steam	6,021,182			
4	Nuclear		23	Requirements Sales for Resale (See instruction 4, page 311.)	100,098
5	Hydro-Conventional				
6	Hydro-Pumped Storage		24	Non-Requirements Sales for Resale (See instruction 4, page 311.)	4,530,663
7	Other				
8	Less Energy for Pumping		25	Energy Furnished Without Charge	
9	Net Generation (Enter Total of lines 3 through 8)	6,021,182	26	Energy Used by the Company (Electric Dept Only, Excluding Station Use)	
10	Purchases	6,419,316	27	Total Energy Losses	567,835
11	Power Exchanges:		28	TOTAL (Enter Total of Lines 22 Through 27) (MUST EQUAL LINE 20)	12,440,498
12	Received				
13	Delivered				
14	Net Exchanges (Line 12 minus line 13)				
15	Transmission For Other (Wheeling)				
16	Received	46,648			
17	Delivered	46,648			
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)	12,440,498			

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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 on line 2 by month the system's output in Megawatt hours for each month.
(3) Report on line 3 by month the non-requirements sales for resale. Include in the monthly amounts any energy losses associated with the sales.
(4) Report on line 4 by month the system's monthly maximum megawatt load (60 minute integration) associated with the system.
(5) Report on lines 5 and 6 the specified information for each monthly peak load reported on line 4.

NAME OF SYSTEM:

Line No.	Month (a)	Total Monthly Energy (b)	Monthly Non-Requirments Sales for Resale & Associated Losses (c)	MONTHLY PEAK Megawatts (See Instr. 4) (d)	MONTHLY PEAK Day of Month (e)	MONTHLY PEAK Hour (f)
29	January	1,311,953	511,655	1,678	25	900
30	February	1,115,443	411,315	1,437	11	800
31	March	1,120,246	451,925	1,304	9	800
32	April	1,061,322	506,990	1,100	15	700
33	May	860,348	301,909	986	31	1700
34	June	984,241	379,559	1,249	9	1400
35	July	1,180,332	551,482	1,247	21	1600
36	August	1,093,446	467,693	1,170	21	1500
37	September	1,042,777	461,623	1,204	2	1600
38	October	909,648	301,347	1,212	30	800
39	November	818,743	138,558	1,392	22	900
40	December	941,999	187,890	1,527	22	900
41	TOTAL	12,440,498	4,671,946			

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/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)	1077	0
7	Plant Hours Connected to Load	6947	0
8	Net Continuous Plant Capability (Megawatts)	0	0
9	When Not Limited by Condenser Water	1060	0
10	When Limited by Condenser Water	1060	0
11	Average Number of Employees	143	0
12	Net Generation, Exclusive of Plant Use - KWh	6021182000	0
13	Cost of Plant: Land and Land Rights	1076546	0
14	Structures and Improvements	40583920	0
15	Equipment Costs	482221177	0
16	Asset Retirement Costs	3337422	0
17	Total Cost	527219065	0
18	Cost per KW of Installed Capacity (line 17/5) Including	480.6884	0.0000
19	Production Expenses: Oper, Supv, & Engr	5473552	0
20	Fuel	172247851	0
21	Coolants and Water (Nuclear Plants Only)	0	0
22	Steam Expenses	4211285	0
23	Steam From Other Sources	0	0
24	Steam Transferred (Cr)	0	0
25	Electric Expenses	68594	0
26	Misc Steam (or Nuclear) Power Expenses	6029249	0
27	Rents	0	0
28	Allowances	1836777	0
29	Maintenance Supervision and Engineering	612731	0
30	Maintenance of Structures	643319	0
31	Maintenance of Boiler (or reactor) Plant	15764360	0
32	Maintenance of Electric Plant	6904381	0
33	Maintenance of Misc Steam (or Nuclear) Plant	709950	0
34	Total Production Expenses	214502049	0
35	Expenses per Net KWh	0.0356	0.0000

Line No.	Item (a)	(b)			(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	2349586	30206	0	0	0	0
39	Avg Heat Cont - Fuel Burned (btu/indicate if nuclear)	12058	138063	0	0	0	0
40	Avg Cost of Fuel/unit, as Delvd f.o.b. during year	73.853	143.795	0.000	0.000	0.000	0.000
41	Average Cost of Fuel per Unit Burned	71.538	137.794	0.000	0.000	0.000	0.000
42	Average Cost of Fuel Burned per Million BTU	2.966	23.763	0.000	0.000	0.000	0.000
43	Average Cost of Fuel Burned per KWh Net Gen	0.028	0.000	0.000	0.000	0.000	0.000
44	Average BTU per KWh Net Generation	9439.000	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	/ /	End of 2008/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
0.0000	0.0000	0.0000	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)			(e)			(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 Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	0700 BIG SANDY, KY	AMOS WV	765.00	765.00	ST	0.13		1
2	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	ALUM	24.20		1
3	0701 BIG SANDY, KY	SARGENTS, OH	765.00	765.00	ST	4.79		1
4	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ALUM	12.65		1
5	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ST	3.04		1
6	0702 BIG SANDY, KY	BROADFORD, VA	765.00	765.00	ALUMT	58.26		1
7	0703 HANGING ROCK, OH	JEFFERSON, IN	765.00	765.00	ST	154.74		1
8	0300 BIG SANDY, KY	TRI-STATE, WV	345.00	345.00	ST	8.36		1
9	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	WP	45.62		1
10	0600 HAZARD, KY	PINEVILLE, KY	161.00	161.00	ST	0.72		1
11	0135 WOOTEN	ARNOLD DELVINTA (LGE)	161.00	161.00	WP	1.09		1
12	0136 WOOTEN EXTENSION		161.00	161.00	ST			1
13	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	ALUM	12.08		1
14	0100 BIG SANDY, KY	BELLEFONTE	138.00	138.00	ST	14.77		1
15	0101 BIG SANDY, KY	W HUNTINGTON, WV	138.00	138.00	ST	0.33		1
16	0102 BELLEFONTE, KY	N PROCTORVILLE, OH	138.00	138.00	ST	1.10	1.10	1
17	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	6.35		1
18	0103 HAZARD, KY	BEAVER CREEK, KY	138.00	138.00	ST	22.35		1
19	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	ST	1.47		1
20	0105 CLINCH RIVER, VA	BEAVER CREEK, KY	138.00	138.00	WP	16.92	16.92	1
21	0107 LOGAN, WV	SPRIGG, KY	138.00	138.00	ST	0.64		2
22	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	ALUMT	32.43		1
23	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	WP	10.05		1
24	0110 BEAVER CREEK, KY	BIG SANDY, KY	138.00	138.00	WP	16.41	0.33	1
25	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	ST	0.71	14.41	1
26	0111 TRI STATE, WV	BELLEFONTE, KY	138.00	138.00	WP	0.38		1
27	0113 CHADWICK	KY ELECTRIC STEEL	138.00	138.00	WP	7.90		1
28	0115 CHADWICK	COALTON	138.00	138.00	WP	0.98		1
29	0133 CHADWICK		138.00	138.00				
30	0117 MILBROOK PARK, OH	FULLERTON	138.00	138.00	WP	5.08	1.58	1
31	0116 BEAVER CREEK	SPICEWOOD	138.00	138.00	WP	26.40		1
32	0120 HATFIELD	SPRIGG	138.00	138.00	WP	5.88		1
33	0121 HATFIELD	INEZ	138.00	138.00	WP	14.67		1
34	0122 INEZ	LOVELY	138.00	138.00	WP	6.86		1
35	0126 INEZ	MARTIKI	138.00	138.00	WP	0.33		1
36					TOTAL	1,238.59	40.26	49

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/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	258	10,045	10,303					1
954 MCMA	554,508	5,448,208	6,002,716					2
								3
954 MCMA	3,159,675	16,507,223	19,666,898					4
								5
								6
351.5 VAR	17,020,130	104,871,454	121,891,584	59,823	462,216		522,039	7
954 MCMA	177,562	1,043,497	1,221,059	1,940	14,988		16,928	8
500 MCMCU	205,938	3,438,906	3,644,844					9
								10
795 MCM 26/7	69,669		69,669					11
795 MCM 26/7		194,639	194,639	11,006	85,033		96,039	12
556.5 VAR	492,656	2,184,682	2,677,338					13
								14
1033.5 VAR	8,672	63,923	72,595					15
397.5 MA	4,478	121,821	126,299					16
397.5 MCMCU	68,294	181,960	250,254					17
								18
636 MCMA	84,068	1,288,061	1,372,129					19
								20
397 MCMA	2,128	444,269	446,397					21
397.5 MCMA	519,478	2,669,387	3,188,865					22
								23
								24
795 MCMA	16,110	609,142	625,252					25
								26
795 MCMA	52,422	246,860	299,282					27
795 MCMA	291,969	422,415	714,384					28
	67,982	914,472	982,454					29
556.5 MCM	408,799	65,178	473,977					30
795 MCMA	555,042	1,724,639	2,279,681					31
1033 MCM		1,506,763	1,506,763					32
10335 VAR	633,040	4,452,788	5,085,828					33
10335 VAR	2,783	571,688	574,471					34
10335 VAR	2,269	56,174	58,443					35
	31,049,447	246,634,249	277,683,696	296,748	2,292,780		2,589,528	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	/ /	End of 2008/Q4

TRANSMISSION LINE STATISTICS

1. Report information concerning transmission lines, cost of lines, and expenses for year. List each transmission line having nominal voltage of 132 kilovolts or greater. Report transmission lines below these voltages in group totals only for each voltage.
2. Transmission lines include all lines covered by the definition of transmission system plant as given in the Uniform System of Accounts. Do not report substation costs and expenses on this page.
3. Report data by individual lines for all voltages if so required by a State commission.
4. Exclude from this page any transmission lines for which plant costs are included in Account 121, Nonutility Property.
5. Indicate whether the type of supporting structure reported in column (e) is: (1) single pole wood or steel; (2) H-frame wood, or steel poles; (3) tower; or (4) underground construction If a transmission line has more than one type of supporting structure, indicate the mileage of each type of construction by the use of brackets and extra lines. Minor portions of a transmission line of a different type of construction need not be distinguished from the remainder of the line.
6. Report in columns (f) and (g) the total pole miles of each transmission line. Show in column (f) the pole miles of line on structures the cost of which is reported for the line designated; conversely, show in column (g) the pole miles of line on structures the cost of which is reported for another line. Report pole miles of line on leased or partly owned structures in column (g). In a footnote, explain the basis of such occupancy and state whether expenses with respect to such structures are included in the expenses reported for the line designated.

Line No.	DESIGNATION		VOLTAGE (KV) (Indicate where other than 60 cycle, 3 phase)		Type of Supporting	LENGTH (Pole miles) (In the case of underground lines report circuit miles)		Number Of
	From (a)	To (b)	Operating (c)	Designed (d)	Structure (e)	On Structure of Line Designated (f)	On Structures of Another Line (g)	Circuits (h)
1	0127 BIG SANDY	INEZ	138.00	138.00	ST	23.00		1
2	0106 DORTON	FLEMING	138.00	138.00	WP	7.64		1
3	0108 BEAVER CREEK	SPRIGG #1	138.00	138.00	WP	32.60		1
4	0124 BIG SANDY	SOUTH NEAL	138.00	138.00	WP	0.01		1
5	0109 BEAVER CREEK	SPRIGG #3	138.00	138.00				
6	0125 BELLEFONTE	AK STEEL OXYGEN PLANT	138.00	138.00	ST	0.22		2
7	0130 JOHNS CREEK	SPRIGG	138.00	138.00	ST	13.00		
8	0131 BAKER	BIG SANDY EXT.	138.00	138.00	ST	1.00		1
9	0128 INEZ	JOHNS CREEK	138.00	138.00	ST	17.00		
10	0129 BEAVER CREEK	JOHNS CREEK	138.00	138.00	ST	22.00		
11	0132 GRANGSTON LOOP		138.00	138.00				
12	0137 HAYS BRANCH	MORGAN FORK	138.00	138.00	ST	8.30		1
13	0138 SOFT SHELL	BEAVER CREEK	138.00	138.00	ST	1.40		2
14	0138 SOFT SHELL	SPICEWOOD	138.00	138.00	ST	1.40		2
15	0139 MORGAN FORK	BETSY LANE	138.00	138.00	ST	0.10		1
16	0139 MORGAN FORK	BEAVER CREEK	138.00	138.00	ST	0.10		1
17								
18	LINES < 132KV		69.00	69.00		593.13	5.92	
19								
20								
21								
22								
23								
24								
25								
26								
27								
28								
29								
30								
31								
32								
33								
34								
35								
36					TOTAL	1,238.59	40.26	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	/ /	End of 2008/Q4

TRANSMISSION LINE STATISTICS (Continued)

7. Do not report the same transmission line structure twice. Report Lower voltage Lines and higher voltage lines as one line. Designate in a footnote if you do not include Lower voltage lines with higher voltage lines. If two or more transmission line structures support lines of the same voltage, report the pole miles of the primary structure in column (f) and the pole miles of the other line(s) in column (g)
8. Designate any transmission line or portion thereof for which the respondent is not the sole owner. If such property is leased from another company, give name of lessor, date and terms of Lease, and amount of rent for year. For any transmission line other than a leased line, or portion thereof, for which the respondent is not the sole owner but which the respondent operates or shares in the operation of, furnish a succinct statement explaining the arrangement and giving particulars (details) of such matters as percent ownership by respondent in the line, name of co-owner, basis of sharing expenses of the Line, and how the expenses borne by the respondent are accounted for, and accounts affected. Specify whether lessor, co-owner, or other party is an associated company.
9. Designate any transmission line leased to another company and give name of Lessee, date and terms of lease, annual rent for year, and how determined. Specify whether lessee is an associated company.
10. Base the plant cost figures called for in columns (j) to (l) on the book cost at end of year.

Size of Conductor and Material (i)	COST OF LINE (Include in Column (j) Land, Land rights, and clearing right-of-way)			EXPENSES, EXCEPT DEPRECIATION AND TAXES				Line No.
	Land (j)	Construction and Other Costs (k)	Total Cost (l)	Operation Expenses (m)	Maintenance Expenses (n)	Rents (o)	Total Expenses (p)	
795 MCMA	1,356,990	12,504,784	13,861,774					1
795 MCMA	217,206	1,174,257	1,391,463					2
397 MCMA	98,056	918,630	1,016,686					3
10335 VAR		116,738	116,738					4
	51,485		51,485					5
795 ACSR	1,393	225,286	226,679					6
1033 MCM		3,833,913	3,833,913					7
1351 KCM	650	1,179,194	1,179,844					8
2-556.5 MCM	1,005,133	9,907,226	10,912,359					9
1033 MCM	195,162	7,528,044	7,723,206					10
	4,103	1	4,104					11
795 ACSR	533,909	9,437,429	9,971,338					12
1590 ACSR		3,537,561	3,537,561					13
1590 ACSR								14
795 ACSR		526,295	526,295					15
795 ACSR				84,974	656,543		741,517	16
								17
	3,187,430	46,706,697	49,894,127	139,005	1,074,000		1,213,005	18
								19
								20
								21
								22
								23
								24
								25
								26
								27
								28
								29
								30
								31
								32
								33
								34
								35
	31,049,447	246,634,249	277,683,696	296,748	2,292,780		2,589,528	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	/ /	End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR

1. Report below the information called for concerning Transmission lines added or altered during the year. It is not necessary to report minor revisions of lines.
2. Provide separate subheadings for overhead and under- ground construction and show each transmission line separately. If actual costs of competed construction are not readily available for reporting columns (l) to (o), it is permissible to report in these columns the

Line No.	LINE DESIGNATION		Line Length in Miles	SUPPORTING STRUCTURE		CIRCUITS PER STRUCTURE	
	From (a)	To (b)	(c)	Type (d)	Average Number per Miles (e)	Present (f)	Ultimate (g)
1	New Lines Added:						
2	Hays Branch	Morgan Fork	8.30	Steel		1	1
3	Morgan Fork Extension		0.20	Steel		1	1
4	Soft Shell Extension		2.80	Steel		1	1
5							
6							
7							
8							
9							
10							
11							
12							
13							
14							
15							
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17							
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30							
31							
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33							
34							
35							
36							
37							
38							
39							
40							
41							
42							
43							
44	TOTAL		11.30			3	3

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

TRANSMISSION LINES ADDED DURING YEAR (Continued)

costs. Designate, however, if estimated amounts are reported. Include costs of Clearing Land and Rights-of-Way, and Roads and Trails, in column (l) with appropriate footnote, and costs of Underground Conduit in column (m).

3. If design voltage differs from operating voltage, indicate such fact by footnote; also where line is other than 60 cycle, 3 phase, indicate such other characteristic.

CONDUCTORS			Voltage KV (Operating)	LINE COST					Line No.
Size (h)	Specification (i)	Configuration and Spacing (j)	(k)	Land and Land Rights (l)	Poles, Towers and Fixtures (m)	Conductors and Devices (n)	Asset Retire. Costs (o)	Total (p)	
									1
795 kcm	ACSR		138	533,909	5,862,088	3,575,341		9,971,338	2
795 kcm	ACSR		138		410,886	115,409		526,295	3
1590 kcm	ACSR		138		2,619,427	918,134		3,537,561	4
									5
									6
									7
									8
									9
									10
									11
									12
									13
									14
									15
									16
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									40
									41
									42
									43
				533,909	8,892,401	4,608,884		14,035,194	44

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	ASHLAND-KY	D	69.00	12.00	
2		D	69.00		
3	BAKER-KY	T	765.00		
4		T	765.00	345.00	34.50
5		T	345.00	138.00	34.50
6		T	69.00	4.00	
7	BARRENSHE-KY	D	69.00	12.00	
8	BEAVER CREEK-KY	T	138.00	69.00	46.00
9		T	138.00	34.50	
10		T	138.00	8.30	
11		T	138.00		
12		T	138.00		
13		T	69.00	12.00	
14	BECKHAM-KY	D	138.00	34.50	
15	BEEFHIDE-KY	D	138.00	34.50	
16	BELFRY-KY	D	46.00	12.00	
17	BELHAVEN-KY	D	138.00	13.09	
18	BELLEFONTE-KY	T	138.00	69.00	34.50
19		T	138.00	34.50	
20		T	138.00	13.09	
21		T	69.00		
22	BETSY LAYNE-KY	T	138.00	69.00	46.00
23		T	138.00	34.00	
24		T	46.00	12.00	
25		T	46.00		
26	BIG SANDY 138KV-KY	T	138.00	69.00	34.50
27		T	138.00	34.50	
28		T	138.00	34.50	12.00
29	BIG SANDY-KY	G	13.80	4.00	
30	BLUE GRASS-KY	D	69.00	12.00	
31	BUSSEYVILLE-KY	D	138.00	34.50	
32	CANNONSBURG-KY	D	69.00	34.50	
33	CEDAR CREEK-KY	T	138.00	69.00	46.00
34		T	138.00	13.09	
35		T	34.50	12.47	
36		T	34.50	12.00	
37	CHADWICK-KY	T	138.00	69.00	34.50
38	COALTON-KY	D	69.00	12.00	
39		D	69.00		
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	3	300	3
1500	3					4
672	1					5
3	1					6
25	1					7
146	2					8
30	1					9
125	1	1				10
			STATCAP	4	235	11
			SVS	1		12
5	1					13
30	1					14
20	1					15
11	1					16
20	1					17
308	2					18
45	1					19
22	1					20
			STATCAP	1	14	21
30	1					22
25	1					23
6	1					24
			STATCAP	1	10	25
90	1					26
20	1					27
9	1					28
7	1					29
11	1					30
55	2					31
25	1					32
90	1					33
11	1					34
1	1					35
4		2				36
200	1	1				37
25	1					38
			STATCAP	1	23	39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS

1. Report below the information called for concerning substations of the respondent as of the end of the year.
2. Substations which serve only one industrial or street railway customer should not be listed below.
3. Substations with capacities of Less than 10 MVa except those serving customers with energy for resale, may be grouped according to functional character, but the number of such substations must be shown.
4. Indicate in column (b) the functional character of each substation, designating whether transmission or distribution and whether attended or unattended. At the end of the page, summarize according to function the capacities reported for the individual stations in column (f).

Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	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	HATFIELD (KP)-KY	T	138.00	69.00	46.00
30	HAZARD-KY	T	161.00	138.00	11.00
31		T	138.00	69.00	12.00
32		T	138.00	34.00	
33		T	138.00		
34		T	69.00		
35		T	34.50	12.00	
36	HENRY CLAY-KY	D	46.00	34.50	
37		D	46.00		
38	HIGHLAND (KP)-KY	D	69.00	12.00	
39		D	69.00	12.00	
40	HITCHINS-KY	D	69.00	12.00	

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
Kentucky Power Company	(1) [X] An Original (2) [ ] A Resubmission	/ /	End of 2008/Q4

SUBSTATIONS (Continued)

5. Show in columns (I), (j), and (k) special equipment such as rotary converters, rectifiers, condensers, etc. and auxiliary equipment for increasing capacity.
6. Designate substations or major items of equipment leased from others, jointly owned with others, or operated otherwise than by reason of sole ownership by the respondent. For any substation or equipment operated under lease, give name of lessor, date and period of lease, and annual rent. For any substation or equipment operated other than by reason of sole ownership or lease, give name of co-owner or other party, explain basis of sharing expenses or other accounting between the parties, and state amounts and accounts affected in respondent's books of account. Specify in each case whether lessor, co-owner, or other party is an associated company.

Capacity of Substation (In Service) (In MVa) (f)	Number of Transformers In Service (g)	Number of Spare Transformers (h)	CONVERSION APPARATUS AND SPECIAL EQUIPMENT Type of Equipment (i)	Number of Units (j)	Total Capacity (In MVa) (k)	Line No.
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
60	1					29
135	3	1				30
180	2					31
30	1					32
			STATCAP	1	32	33
			STATCAP	2	68	34
8	1					35
30	1					36
			STATCAP	1	10	37
11	1					38
3		1				39
25	1					40

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SUBSTATIONS

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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	D	138.00	69.00	13.09
4		D	138.00	37.27	13.80
5		D	138.00	37.00	
6		D	138.00		
7		D	138.00		
8		D	69.00		
9		D	26.00		
10		D	26.00	18.60	
11	JACKSON-KY	T	69.00	12.00	
12		T	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	12.00	
18	KEYSER-KY	D	69.00	12.00	
19	LESLIE-KY	T	161.00	69.00	12.00
20		T	161.00		
21		T	69.00	34.00	12.00
22	LOUISA-KY	D	34.50	12.00	
23	LOVELY-KY	D	138.00	34.00	
24	MAYKING-KY	D	69.00	12.00	
25	MAYO TRAIL-KY	D	69.00	12.00	
26	MCKINNEY-KY	D	46.00	34.00	
27		D	34.50	12.00	
28	NEW CAMP-KY	D	69.00	12.00	
29	OLIVE HILL-KY	D	69.00	12.00	
30		D	69.00	4.00	
31	PAINTSVILLE-KY	D	46.00	12.00	
32		D	46.00	7.20	
33	PIKEVILLE-KY	D	69.00	12.00	
34	PRINCESS-KY	D	69.00	34.50	
35		D	69.00		
36	REEDY COAL-KY	D	69.00	34.00	
37	RUSSELL-KY	D	69.00	12.00	
38	SALISBURY (KP)-KY	D	46.00	12.00	
39	SIDNEY-KY	D	69.00	12.00	
40					

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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
13	2					11
			STATCAP	1	10	12
11	1					13
90	1					14
			STATCAP	1	53	15
			STATCAP	1	10	16
20	1					17
20	1					18
90	1					19
			AIR CORE REACTOR	3		20
20	1					21
10	2					22
30	1					23
20	1					24
25	1					25
20	1					26
7	1					27
20	1					28
8	1					29
5	1					30
8	1					31
5	3					32
25	1					33
20	1					34
			STATCAP	1	22	35
20	1					36
22	1					37
20	1					38
20	1					39
						40

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year/Period of Report
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SUBSTATIONS

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Line No.	Name and Location of Substation (a)	Character of Substation (b)	VOLTAGE (In MVa) Primary (c)	Secondary (d)	Tertiary (e)
1	SLEMP-KY	D	69.00	34.50	
2		D	69.00	34.00	
3	SOFT SHELL-KY	D	138.00	34.50	
4	SOUTH PIKEVILLE-KY	D	69.00	12.00	
5	STINNETT-KY	D	161.00	34.50	7.20
6		D	161.00	34.00	7.20
7	STONE-KY	T	138.00	69.00	46.00
8	TENTH STREET-KY	D	69.00	12.00	
9	THELMA-KY	T	138.00	69.00	46.00
10		T	138.00		
11		T	46.00		
12	TOM WATKINS-KY	D	69.00	12.00	
13	TOPMOST-KY	D	138.00	13.09	
14	VICCO-KY	D	138.00	34.50	
15	WEST PAINTSVILLE-KY	D	69.00	12.00	
16	WHITESBURG-KY	D	69.00	12.00	
17		D	69.00		
18	WURTLAND-KY	D	69.00	12.00	
19					
20	32 STATIONS UNDER 10 MVA	T/D			
21					
22					
23					
24					
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39					
40					

Name of Respondent Kentucky Power Company	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Date of Report (Mo, Da, Yr) / /	Year/Period of Report End of 2008/Q4

SUBSTATIONS (Continued)

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11	1					1
20	1					2
30	1					3
25	1					4
22	1	1				5
15	1					6
50	1					7
42	2					8
50	1					9
			STATCAP	1	32	10
			STATCAP	1	7	11
11	1					12
20	1					13
30	1					14
20	1					15
21	2					16
			STATCAP	1	13	17
20	1					18
						19
172	30					20
						21
						22
						23
						24
						25
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						36
						37
						38
						39
						40

INDEX

Schedule	Page No.