COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

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MAY 13 2011

PUBLIC SERVICE COMMISSION

In the matter of:

JOINT APPLICATION OF KENTUCKY POWER COMPANY, AMERICAN ELECTRIC POWER COMPANY, INC. AND CENTRAL AND SOUTH WEST CORPORATION REGARDING A PROPOSED MERGER	)	CASE NO. 99-149

RESPONSE OF KENTUCKY POWER COMPANY

Reporting Period: Year Ending December 31, 2010

May 13, 2011

Kentucky Power Company

REQUEST

Furnish annual financial statements of AEP, including consolidating adjustments of AEP and its subsidiaries with a brief explanation of each adjustment and all periodic reports filed with the SEC. Including but not limited to the U5S and U-13-60 reports. All subsidiaries should prepare and have available monthly and annual financial information required to compile financial statements and to comply with other reporting requirements. The financial statements for any non-consolidated subsidiaries of AEP should be furnished to the Commission. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, Pg. 10 (Periodic Reports)]

RESPONSE

In July 2007, Kentucky Power Company filed a request with the Securities and Exchange Commission to cease acting as a registered company. Consequently, Kentucky Power Company is no longer included in AEP's Form 10-K. Upon notifying the Kentucky Public Service Commission of its de-registration, Kentucky Power agreed to provide the Executive Director and the Financial Analysis Division a copy of AEP's Form 10-K. Two copies of the report were filed with the Commission on April 29, 2011 under the subject reference *Kentucky Power Company Holding Company File.*

Attachment A to this response is a copy of Kentucky Power Company's 2010 Annual Report. The SEC Form U-13-60 has been replaced as FERC Form 60, and a copy is provided herewith as Attachment B. The SEC Form U5S is no longer required to be filed due to the repeal of the Public Utility Holding Company Act of 1935.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

On an annual basis file a general description of the nature of inter-company transactions with specific identification of major transactions 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. [Reference: Merger Agt., Ky. PSC Order dated 6-14-99, pg. 11, Item 1]

RESPONSE

A general description of the nature of inter-company transactions is contained in the Cost Allocation Manual (CAM) most recently filed December 2009 as Volume 1-A in Case No. 2009-00459. There have been no changes to the procedures used to price inter-company transactions from those used in the prior year. Unless exempted, inter-company transactions conducted by or with Kentucky Power Company are priced at fully-allocated cost in accordance with the Public Utility Holding Company Act of 2005.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

On an annual basis file a report that identifies professional personnel transferred from Kentucky Power to AEP or any of the non-utility subsidiaries and describes the duties performed by each employee while employed by Kentucky Power and to be performed subsequent to transfer. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2.]

RESPONSE

Page 2 of this response is a listing of employees transferred from Kentucky Power Company to AEP or one of its subsidiaries during the year ended December 31, 2010.

WITNESS: Lila P Munsey

Kentucky Power Company
Listing of Transferees
Year ended 12/31/2010

Company/Employee Name	Transfer Date	New Title	Previous Title
Columbus Southern Power Co			
Messer Jr., James H	8/21/2010	Distr Dispatcher II	Distr Dispatcher II
AEP Service Corporation			
Dillow II, Harold E	6/26/2010	Region Engineering Supv	Maintenance Supt II
SouthWestern Electric Power Co			
Kennedy, Holland B	3/6/2010	Energy Production Supv III	Energy Production Supv III

Kentucky Power Company

REQUEST

AEP should file on a quarterly** basis a report detailing Kentucky Power's proportionate share of AEP's total operating revenues, operating revenues, operating and maintenance expenses, and number of employees. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 2]

**Note: Pursuant to the Commission's Order dated June 14, 2004, the information pertaining to this data request shall be filed on an annual basis.

RESPONSE

Kentucky Power Company Report Proportionate Share of AEP 12 Months Ending December 31, 2010 (in millions, except number of employees)			
	AEP	**KPCo**	**Share**
Revenues	$14,427	$626**	4.3%
Operating/Maintenance Expense*	$9,303	$316	3.4%
No. of Employees as of 12/31/2010	18,622	417	2.2%

* Includes Fuel expense of $4,029 million for AEP and $186 million for KPCo
** Includes sales to affiliates of $60 million for KPCo

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP should file any contracts or other agreements concerning the transfer of such assets or the pricing of inter-company transactions with the Commission at the time the transfer occurs. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, (Special Reports)]

**Note: Pursuant to the Commission's Order dated June 14, 2004, the information pertaining to this response shall be filed on an annual basis.

RESPONSE

During the year ended December 31, 2010, there were 24 separate transactions in which Kentucky Power sold assets to its affiliates.

The assets transferred were meters and transformers. The total value of the assets transferred was $487,477.

The smallest transfer was 1 meter for $53 and the largest was 394 meters for $91,804.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP should file a quarterly** report of the number of employees of AEP and each subsidiary on the basis of payroll assignment. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 11, Item 1 (Special Reports)]

**Note: Pursuant to the Commission's Order dated June 14, 2004, the information pertaining to this data request shall be filed on an annual basis.

RESPONSE

The chart below lists the number of AEP employees on the basis of payroll assignment for each AEP subsidiary for the year ended December 31, 2010.

Description	Employee Count
Kingsport Power Company	51
Appalachian Power Company	2,170
Kentucky Power Company	417
Indiana Michigan Power Company	2,361
Wheeling Power Company	52
Ohio Power Company	2,089
Columbus Southern Power Co	1,053
River Transportation Div I&MP	329
Conesville Coal Prep Co	22
AEP Service Corporation	5,111
AEP Texas Central Company	1,002
CSW Energy, Inc.	24
AEP Elmwood LLC	120
AEP River Operations LLC	982
Public Service Co. of OK	1,145
SouthWestern Electric Power Co	1,375
AEP Texas North Company	319
Total	18,622

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP should file an annual report containing the years of service at Kentucky Power and the salaries of professional employees transferred from Kentucky Power to AEP or its subsidiaries filed in conjunction with the annual transfer of employees report. [Reference: Merger Agt., Ky. PSC Order 6/14/99, Reporting Requirements, Pg. 12, Item 2]

RESPONSE

Please see Page 2 of this response for a listing of Kentucky Power Company employees who have transferred from Kentucky Power to AEP or one of its subsidiaries within the year ended December 31, 2010.

WITNESS: Lila P Munsey

Kentucky Power Company
Listing of Transferees
Year ended 12/31/2010

Company/ Employee Name	Transfer Date	Total Years of Service	Annual Salary
Columbus Southern Power Co			
Messer Jr., James H	8/21/2010	32.0	$69,666
AEP Service Corporation			
Dillow II, Harold E	6/26/2010	28.0	$112,812
SouthWestern Electric Power Co			
Kennedy, Holland B	3/6/2010	28.8	$85,000

Kentucky Power Company

REQUEST

AEP should file an annual report of cost allocation factors in use, supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 3]

RESPONSE

The allocation factors used by Kentucky Power Company and other AEP System companies are described in the Cost Allocation Manual (CAM) that was most recently filed December 2009 as Volume 1-A in Case No. 2009-00459. Specifically, section 99-00-04 provides a full list of allocation factors available for use.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP should file summaries of any cost allocation studies when conducted and the basis for the methods used to determine the cost allocation in effect. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 4]

**Note: Pursuant to the Commission's Order dated June 14, 2004, the information pertaining to this data request shall be filed on an annual basis.

RESPONSE

Kentucky Power Company did not perform any cost allocation studies during the year ended December 31, 2010. The methods used by Kentucky Power Company for cost allocation are documented in the AEP Cost Allocation Manual (CAM).

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP should file an annual report of the methods used to update or revise the cost allocation factors in use supplemented upon significant change. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 5]

RESPONSE

The methods used to update or revise the cost allocation factors used by Kentucky Power Company and other AEP System companies were not significantly changed during the year ended December 31, 2010. Allocation factors are revised periodically each year (e.g. monthly, quarterly, semi-annually and annually) based on the most current statistics available for each factor. The allocation factors in use are documented in the Cost Allocation Manual (CAM) most recently filed with the Commission on December 29, 2009 as Volume 1-A in Case No. 2009-00459.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP should file the current Articles of Incorporation and bylaws of affiliated companies in businesses related to the electric industry or that would be doing business with AEP. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 6]

RESPONSE

Due to the voluminous nature of the response, the Company is providing a list of AEP's subsidiaries. After the Commission Staff has an opportunity to review the list, the Company will make available a copy of the Articles of Incorporation and By-Laws of any affiliate the Staff deems necessary for review.

WITNESS: Lila P Munsey

CorpCharts - Subsidiary Chart for American Electric Power Company, Inc.

Effective Date: 5/10/2011

Report Date: 5/10/2011

- American Electric Power Company, Inc.
  - AEP C & I Company, LLC (100%)
    - AEP Retail Energy Partners LLC (100%)
    - AEP Texas Commercial & Industrial Retail GP, LLC (100%)
      - AEP Texas Commercial & Industrial Retail Limited Partnership (0.50%)
    - AEP Texas Commercial & Industrial Retail Limited Partnership (99.50%)
    - REP Holdco, LLC (100%)
      - Mutual Energy SWEPCO, LP (99.50%)
      - REP General Partner, L.L.C. (100%)
        - Mutual Energy SWEPCO, LP (0.50%)
  - AEP Coal, Inc. (100%)
    - AEP Kentucky Coal, LLC (100%)
    - Snowcap Coal Company, Inc. (100%)
  - AEP Credit, Inc. (100%)
  - AEP Fiber Venture, LLC (100%)
    - AFN, LLC (50.42%)
  - AEP Generating Company (100%)
  - AEP Investments, Inc. (100%)
    - Amperion, Inc. (0.11%)
    - IntercontinentalExchange, Inc. (0.48%)
    - Microcell Corporation (1%)
    - Powerspan Corp. (0.83%)
    - Universal Supercapacitors, LLC (50%)
  - AEP Nonutility Funding LLC (100%)
  - AEP Pro Serv, Inc. (100%)
    - Diversified Energy Contractors Company, LLC (100%)
    - United Sciences Testing, Inc. (100%)
  - AEP Resources, Inc. (100%)
    - AEP Energy Services Limited (100%)
    - AEP Energy Services, Inc. (100%)

- AEP Energy Services Gas Holding Company (100%)
- AEP River Operations LLC (100%)
  - AEP Elmwood LLC (100%)
    - Conlease, Inc. (100%)
    - International Marine Terminals Partnership (33.33%)
      - IMT Land Corp. (100%)
- AEP T&D Services, LLC (100%)
- AEP Transmission Holding Company, LLC (100%)
  - AEP Transmission Company, LLC (100%)
    - AEP Appalachian Transmission Company, Inc. (100%)
    - AEP Indiana Michigan Transmission Company, Inc. (100%)
    - AEP Kentucky Transmission Company, Inc. (100%)
    - AEP Ohio Transmission Company, Inc. (100%)
    - AEP Oklahoma Transmission Company, Inc. (100%)
    - AEP Southwestern Transmission Company, Inc. (100%)
    - AEP West Virginia Transmission Company, Inc. (100%)
  - AEP Transmission Partner LLC (100%)
    - Electric Transmission America, LLC (0.50%)
      - Prairie Wind Transmission, LLC (50%)
      - Tallgrass Transmission, LLC (50%)
    - Electric Transmission Texas, LLC (0.50%)
  - Electric Transmission America, LLC (49.50%)
    - Prairie Wind Transmission, LLC (50%)
    - Tallgrass Transmission, LLC (50%)
  - Ohio Series, Potomac-Appalachian Transmission Highline, LLC (50%)
  - PATH West Virginia Series (50%)
    - PATH West Virginia Transmission Company, LLC (100%)
      - PATH - WV Land Acquisition Company (100%)
  - Pioneer Transmission, LLC (50%)
  - Potomac-Appalachian Transmission Highline, LLC (50%)
- AEP Utilities, Inc. (100%)
  - AEP Texas Central Company (100%)

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Calendar Year 2010
Order Dated June 14, 1999
Item No. 11
Page 3 of 5

- AEP Texas Central Transition Funding II LLC (100%)
- AEP Texas Central Transition Funding LLC (100%)
- AEP Texas North Company (100%)
  - AEP Texas North Generation Company, LLC (100%)
- CSW Energy Services, Inc. (100%)
  - Nuvest, LLC (92.90%)
    - ESG Manufacturing, LLC (100%)
    - ESG, L.L.C. (50%)
    - National Temporary Services, Inc. (100%)
- CSW Energy, Inc. (100%)
  - AEP Desert Sky GP, LLC (100%)
    - Desert Sky Wind Farm LP (1%)
  - AEP Desert Sky LP II, LLC (100%)
    - Desert Sky Wind Farm LP (99%)
  - AEP Energy Partners, Inc. (100%)
  - AEP Wind Holding, LLC (100%)
    - AEP Properties, LLC (100%)
    - AEP Wind GP, LLC (100%)
      - Trent Wind Farm, LP (1%)
    - AEP Wind LP II, LLC (100%)
      - Trent Wind Farm, LP (99%)
- Electric Transmission Texas, LLC (49.50%)

- AEP Utility Funding, LLC (100%)
- American Electric Power Service Corporation (100%)
  - American Electric Power Foundation (100%)
- Appalachian Power Company (98.70%)
  - Cedar Coal Co. (100%)
  - Central Appalachian Coal Company (100%)
  - Central Coal Company (50%)
  - Southern Appalachian Coal Company (100%)
- Columbus Southern Power Company (100%)
  - Conesville Coal Preparation Company (100%)

- Distribution Vision 2010, LLC (23.40%)
- Ohio Valley Electric Corporation (4.30%)
  - Indiana-Kentucky Electric Corporation (100%)
- Franklin Real Estate Company (100%)
  - Indiana Franklin Realty, Inc. (100%)
- Indiana Michigan Power Company (100%)
  - Blackhawk Coal Company (100%)
  - Price River Coal Company, Inc. (100%)
- Kentucky Power Company (100%)
- Kingsport Power Company (100%)
- Ohio Power Company (99.40%)
  - Cardinal Operating Company (50%)
  - Central Coal Company (50%)
  - JMG Funding, Limited Partnership (99%)
  - OP Gavin, LLC (100%)
    - JMG Funding, Limited Partnership (1%)
- Ohio Valley Electric Corporation (39.17%)
  - Indiana-Kentucky Electric Corporation (100%)
- PowerTree Carbon Company, LLC (12.01%)
- Public Service Company Of Oklahoma (99.40%)
- Southwestern Electric Power Company (99.40%)
  - Arkansas Coalition for Affordable and Reliable Electricity, LLC (50%)
  - Dolet Hills Lignite Company, LLC (100%)
  - Oxbow Lignite Company, LLC (50%)
  - Southwest Arkansas Utilities Corporation (100%)
  - The Arklahoma Corporation (47.60%)
- Wheeling Power Company (100%)

Kentucky Power Company

REQUEST

AEP should file the current Articles of Incorporation of affiliated companies involved in non-related business.
[Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pg. 12, Item 7]

RESPONSE

Please see the Company's response to Item No. 11.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

To the extent that the merger is subject to conditions or changes not reviewed in this case, the Joint Applicants should amend their filing to allow the Commission and all parties an opportunity to review the revisions to ensure that Kentucky Power and its customers are not adversely affected and that any additional benefits flow through the favored nations clause. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Reporting Requirements, Pgs. 12-13]

RESPONSE

There were no changes during the year ended December 31, 2010 to the terms and conditions of the settlement agreements in any of the jurisdictions subject to the merger that would adversely affect the settlement reached in the Commonwealth of Kentucky or cause additional benefits to flow through the favored nations clause.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

The Joint Applicants should submit copies of final approval received from the FERC, SEC, FTC, DOJ, and all state regulatory commissions to the extent that these documents have not been provided. With each submittal, the Joint Applicants shall further state whether Paragraph 10 of the Settlement Agreement requires changes to the regulatory plan approved herein. [Reference: Merger Agt., Ky. PSC Order dated 6/14/99, Pg. 14, Item 7]

RESPONSE

Please see the Company's response to Item No. 14 as filed with the Commission on December 8, 2000.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Provide annual Service Reliability Report addressing the duration and frequency of customer disruptions (CAIDI and SAIFI), including storms for calendar 2010. [Reference: Merger Agt., Attachment C, Pg. 1, Item l]

RESPONSE

The overall Customer Average Interruption Duration Index (CAIDI) including Major Event Days (MED) for Kentucky Power Company (KPCo) customers during calendar year 2010 was 208.1 minutes per customer interrupted. The overall System Average Interruption Frequency Index (SAIFI) including MED for KPCo customers during calendar year 2010 was 2.751 interruptions per customer served.

KPCo has previously reported on its changes in outage reporting systems. Making comparisons to the 1995-1998 values is very difficult because of the numerous advancements in outage recording technology. The ultimate results are more accurate outage customer count and outage duration values.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Provide annual Call Center Performance Measures for those centers that handle Kentucky customer calls (Call Center Average Speed of Answer (ASA) Abandonment Rate, and Call Blockage), for calendar year 2010. [Reference: Merger Agt., Attachment C, Pg. 1, Item 2]

RESPONSE

The annual Call Center Performance Measures for those centers that handle Kentucky customer calls for the calendar year 2010 are: Average Speed of Answer (ASA): 96 seconds, Abandonment Rate: 10.96%, and Call Blockage: 7.87%.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Will continue to completely inspect its Kentucky electric facilities every two years and perform tree trimming, lightning arrestor replacement, animal guarding and pole and cross arm replacements. Provide data for calendar year 2010. [Reference: Merger Agt., Case 99-149, Attachment C, Page l, Item 3]

RESPONSE

During the calendar year 2010, Kentucky Power continued to perform circuit inspections, tree trimming, lightning arrester replacement, cutout replacement, animal guarding, and pole and cross arm replacements.

Moreover, in connection with the Settlement Agreement in Case No. 2009-00459, Kentucky Power is working toward implementing a four-year cycle based distribution vegetation management program. Kentucky Power provides the following statistics for work in its service territory in 2010:

Inspected 126 complete circuits.
Replaced 291 deteriorated wood poles.
Completed right-of-way maintenance on 1,569 miles of distribution line.
Replaced 1,002 cutouts and 510 lightning arresters under our cutout and arrester replacement program.
Installed 404 animal guards.

Kentucky Power continues its asset management programs to review the performance of its facilities and to make prudent improvements to continue providing reliable and cost-effective electric service to its Kentucky customers.

In accordance with the Settlement Agreement in Case No. 2009-00459, the Company has agreed to increase its annual distribution vegetation management spending by $10 million beyond the test year amount of $7.2 million. During 2010, the Company exceeded the Settlement Agreement level by $343,754.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

AEP/Kentucky Power management will compile outage data detailing each circuit's reliability performance. In addition, by monitoring repeated outages on a regular basis, the Company will identify and resolve reliability problems, which may go unnoticed by using CAIDI and SAIFI results. This data will be coupled with feedback from district field personnel and supervision and management concerning other locations and situations where the impact of outages are quantified. This process will be used to develop a comprehensive work plan each year, which focuses efforts to improve service reliability. The Company will undertake all reasonable expenditures to achieve the goal of limiting customer outages. [Reference: Merger Agt., Attachment C, Pg. 1, Item 4]

RESPONSE

Kentucky Power continues to compile outage data detailing each circuit's reliability performance. Worst performing circuits are identified considering SAIFI, CAIDI and SAIDI. Circuits or circuit segments with repeat outages are identified as well as those with outage causes that can be addressed through existing asset improvement programs targeting animal, lightning, small conductor failures and tree caused outages. This allows for the identification of areas needing reliability improvements and for the development of work plans to optimize system performance where within utility control.

As part of its settlement of Case No. 2009-00459, the Company is implementing a four-year cycle based distribution vegetation management program. Work plans are developed by combining reliability performance with input from field personnel to identify areas that do not satisfy ranking criteria alone. Work plans include ground-line inspection and treatment of poles; improved fault isolation by installing additional sectionalizing devices; recloser maintenance; and system improvements required due to facility loading, voltage control and reliability performance.

In accordance with the Commission's Order dated June 28, 2010, in Case No. 2009-00459, the Company submits annually by September 30 the distribution reliability vegetation management work plan for the upcoming year. The Company has also agreed to notify the Commission in writing of any material deviation from the filed work plan.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Plans to continue to maintain a high quality workforce to meet customers' needs. [Reference: Merger Agt, Attachment C, Pg. 2, Item 5]

RESPONSE

The Company commits to maintain a high quality workforce to continue providing electrical services to meet the customers' needs.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP shall designate an employee who will act as a contact for State Commissions 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 a State 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 an AEP operating company from which the information is sought. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item Q]

RESPONSE

Kentucky Power Company's Managing Director, Regulatory and Finance, Mr. Ranie K. Wohnhas, is the designated contact for the Kentucky Public Service Commissioners, Commission Staff, and the Kentucky Attorney General's office regarding affiliate transactions and personnel transfers.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

Please provide designated employee or agent within Kentucky who will act as a contact for retail customers regarding service and reliability concerns and provide a contact for retail consumers for information, questions and assistance. Such AEP/Kentucky Power representative shall be able to deal with billing, maintenance and service reliability issues. [Merger Agt., Stipulation and Settlement, Pg. 11, Item R]

RESPONSE

The Company would prefer that customers initially call the Customer Solution Center's (CSC) toll free telephone number. The customer associates of the CSC are capable of answering questions concerning utility service, reliability and billing issues. However, the Kentucky Power Company Regulatory Services Department, specifically the Managing Director of Regulatory and Finance, is capable of dealing with billing, maintenance, and service reliability concerns.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP shall provide each signatory state a current list of employees or agents that are designated to work with each State Commission and consumer advocate concerning state regulatory matters, including, but not limited to, rate cases, consumer complaints, billing and retail competition issues. [Reference: Merger Agt., Stipulation and Settlement, Pg. 11, Item 5.]

RESPONSE

Kentucky Power Company's Managing Director, Regulatory and Finance, Mr. Ranie K. Wohnhas, and the Regulatory Services Department Staff are the designated employees to work with the Kentucky Public Service Commission and the Kentucky Attorney General's office concerning state regulatory matters, including, but not limited to rate cases, consumer complaints, billing and retail competition issues.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

The Company further commits to maintain in Kentucky a sufficient management team to ensure that safe, reliable and efficient electric service is provided and to respond to the needs and inquiries of its Kentucky customers.
[Reference: Merger Agt., Attachment C, Pg. 2, Item 6a]

RESPONSE

The Company has maintained a sufficient management team in Kentucky to ensure that safe, reliable and efficient electric service is provided, as well as to respond to customers' needs and inquiries.

WITNESS: Lila P Munsey

Kentucky Power Company

REQUEST

AEP shall contract with an independent auditor who shall conduct biennial audits for ten years after merger consummation of affiliated transactions to determine compliance with the affiliate standards outlined in the Stipulation and Settlement Agreement. The results of such audits shall be filed with the State commissions. Prior to the initial audit, AEP will conduct an informational meeting with State Commissions regarding how its affiliates and affiliate transactions will or have changed as a result of the proposed merger.
[Reference: Stipulation and Settlement Agreement, Page 11, Section 8(V)]

RESPONSE

Kentucky Power Company continues to adhere to all applicable affiliate standards. In light of the Kentucky General Assembly's enactment of HB 897 (KRS 278.2201 et seq.) in 2000, and the express terms of the Merger Settlement Agreement and the Order approving the agreement, the affiliate standards and requirements contained in the Merger Settlement Agreement have been superseded by statute. *See: Order, Joint Application of Kentucky Power Company, American Electric Power Company, Inc. and Central and South West Corporation Regarding a Proposed Merger, P.S.C. Case No. 99-149 at page 8 (affiliate standards and guidelines set out in Merger Settlement Agreement to remain in effect "until new affiliate standards imposed by either the Commission or by the General Assembly.").* Accordingly, Kentucky Power Company will not be conducting a biennial audit of affiliated transactions as contemplated by the now superseded standards.

WITNESS: Lila P Munsey

KPSC Case No. 99-149
Item No. 1
Attachment A

Kentucky Power Company

2010 Annual Report

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MAY 13 2011
PUBLIC SERVICE
COMMISSION

Financial Statements

AEP AMERICAN ELECTRIC POWER

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GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
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.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
CO_2	Carbon Dioxide and other greenhouse gases.
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, as amended, by and among PSO and SWEPCo governing generating capacity allocation. 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 nonaffiliated captive insurance company.
ERCOT	Electric Reliability Council of Texas.
FAC	Fuel Adjustment Clause.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
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.
MMBtus	Million British Thermal Units.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
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.

Term	Meaning
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.
RTO	Regional Transmission Organization.
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.
VIE	Variable Interest Entity.
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, 2010 and 2009, 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, 2010. 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, 2010 and 2009, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2010 in conformity with accounting principles generally accepted in the United States of America.

Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

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KENTUCKY POWER COMPANY
STATEMENTS OF INCOME
For the Years Ended December 31, 2010, 2009 and 2008
(in thousands)

	2010	2009	2008
REVENUES			
Electric Generation, Transmission and Distribution	$ 623,100	$ 567,564	$ 597,699
Sales to AEP Affiliates	60,005	62,613	66,249
Other Revenues	567	2,349	1,612
TOTAL REVENUES	683,672	632,526	665,560
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	185,938	188,525	171,215
Purchased Electricity for Resale	21,422	24,839	26,157
Purchased Electricity from AEP Affiliates	208,400	198,320	234,379
Other Operation	68,972	51,417	64,330
Maintenance	46,223	38,888	47,921
Depreciation and Amortization	52,867	52,010	48,067
Taxes Other Than Income Taxes	10,995	11,738	9,644
TOTAL EXPENSES	594,817	565,737	601,713
OPERATING INCOME	88,855	66,789	63,847
Other Income (Expense):			
Interest Income	239	218	2,103
Allowance for Equity Funds Used During Construction	768	391	1,012
Interest Expense	(36,442)	(33,812)	(34,535)
INCOME BEFORE INCOME TAX EXPENSE	53,420	33,586	32,427
Income Tax Expense	18,138	9,650	7,896
NET INCOME	$ 35,282	$ 23,936	$ 24,531

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, 2010, 2009 and 2008
(in thousands)

	Common Stock	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2007	$ 50,450	$ 208,750	$ 128,583	$ (814)	$ 386,969
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $197			(365)		(365)
Common Stock Dividends			(14,000)		(14,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					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
TOTAL COMMON 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			(19,500)		(19,500)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					408,508
COMPREHENSIVE INCOME					
Other Comprehensive Loss, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $355				(660)	(660)
NET INCOME			23,936		23,936
TOTAL COMPREHENSIVE INCOME					23,276
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2009	50,450	238,750	143,185	(601)	431,784
Common Stock Dividends			(21,000)		(21,000)
SUBTOTAL – COMMON SHAREHOLDER'S EQUITY					410,784
COMPREHENSIVE INCOME					
Other Comprehensive Income, Net of Taxes:					
Cash Flow Hedges, Net of Tax of $81				150	150
NET INCOME			35,282		35,282
TOTAL COMPREHENSIVE INCOME					35,432
TOTAL COMMON SHAREHOLDER'S EQUITY - DECEMBER 31, 2010	$ 50,450	$ 238,750	$ 157,467	$ (451)	$ 446,216

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
ASSETS
December 31, 2010 and 2009
(in thousands)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 281	$ 494
Advances to Affiliates	67,060	-
Accounts Receivable:		
Customers	21,652	17,593
Affiliated Companies	17,616	8,692
Accrued Unbilled Revenues	3,823	4,806
Miscellaneous	587	1,304
Allowance for Uncollectible Accounts	(623)	(851)
Total Accounts Receivable	43,055	31,544
Fuel	16,640	36,168
Materials and Supplies	24,378	18,248
Risk Management Assets	8,697	13,687
Accrued Tax Benefits	1,420	29,540
Margin Deposits	5,357	5,925
Prepayments and Other Current Assets	1,497	2,416
TOTAL CURRENT ASSETS	168,385	138,022
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	553,589	547,378
Transmission	444,303	438,775
Distribution	590,606	569,389
Other Property, Plant and Equipment	63,982	59,002
Construction Work in Progress	34,093	28,409
Total Property, Plant and Equipment	1,686,573	1,642,953
Accumulated Depreciation and Amortization	542,443	508,806
TOTAL PROPERTY, PLANT AND EQUIPMENT – NET	1,144,130	1,134,147
OTHER NONCURRENT ASSETS		
Regulatory Assets	213,593	206,074
Long-term Risk Management Assets	8,030	9,498
Deferred Charges and Other Noncurrent Assets	37,946	40,178
TOTAL OTHER NONCURRENT ASSETS	259,569	255,750
TOTAL ASSETS	$ 1,572,084	$ 1,527,919

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
BALANCE SHEETS
LIABILITIES AND SHAREHOLDER'S EQUITY
December 31, 2010 and 2009

	2010	2009
	(in thousands)	
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 485
Accounts Payable:		
General	33,334	42,595
Affiliated Companies	45,790	27,341
Risk Management Liabilities	5,959	5,190
Customer Deposits	19,692	18,258
Accrued Taxes	23,741	12,625
Accrued Interest	7,570	7,466
Other Current Liabilities	26,227	26,996
TOTAL CURRENT LIABILITIES	162,313	140,956
NONCURRENT LIABILITIES		
Long-term Debt – Nonaffiliated	528,888	528,722
Long-term Debt – Affiliated	20,000	20,000
Long-term Risk Management Liabilities	2,303	4,101
Deferred Income Taxes	316,389	304,549
Regulatory Liabilities and Deferred Investment Tax Credits	34,991	35,678
Employee Benefits and Pension Obligations	49,298	49,843
Deferred Credits and Other Noncurrent Liabilities	11,686	12,286
TOTAL NONCURRENT LIABILITIES	963,555	955,179
TOTAL LIABILITIES	1,125,868	1,096,135
Rate Matters (Note 2)		
Commitments and Contingencies (Note 4)		
COMMON SHAREHOLDER'S EQUITY		
Common Stock – Par Value – $50 Per Share:		
Authorized – 2,000,000 Shares		
Outstanding – 1,009,000 Shares	50,450	50,450
Paid-in Capital	238,750	238,750
Retained Earnings	157,467	143,185
Accumulated Other Comprehensive Income (Loss)	(451)	(601)
TOTAL COMMON SHAREHOLDER'S EQUITY	446,216	431,784
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ 1,572,084	$ 1,527,919

See Notes to Financial Statements.

KENTUCKY POWER COMPANY
STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009 and 2008
(in thousands)

	2010	2009	2008
OPERATING ACTIVITIES			
Net Income	$ 35,282	$ 23,936	$ 24,531
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	52,867	52,010	48,067
Deferred Income Taxes	1,075	50,612	4,097
Deferral of Storm Costs	-	(24,355)	-
Allowance for Equity Funds Used During Construction	(768)	(391)	(1,012)
Mark-to-Market of Risk Management Contracts	5,651	(2,386)	(4,650)
Pension Contributions to Qualified Plan Trust	(6,184)	-	-
Fuel Over/Under-Recovery, Net	(923)	11,740	(5,528)
Change in Other Noncurrent Assets	7,084	1,452	(11,298)
Change in Other Noncurrent Liabilities	(4,619)	(2,943)	2,055
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(12,035)	(444)	8,317
Fuel, Materials and Supplies	14,512	(13,643)	(18,866)
Accounts Payable	11,228	(7,149)	21,288
Accrued Taxes, Net	37,721	(29,470)	(4,199)
Other Current Assets	1,514	(1,177)	(3,953)
Other Current Liabilities	1,198	(2,997)	2,473
Net Cash Flows from Operating Activities	143,603	54,795	61,322
INVESTING ACTIVITIES			
Construction Expenditures	(54,058)	(63,963)	(129,619)
Change in Advances to Affiliates, Net	(67,060)	-	-
Acquisitions of Assets	(254)	(316)	(314)
Proceeds from Sales of Assets	700	927	947
Net Cash Flows Used for Investing Activities	(120,672)	(63,352)	(128,986)
FINANCING ACTIVITIES			
Capital Contribution from Parent	-	30,000	-
Issuance of Long-term Debt – Nonaffiliated	-	129,292	-
Change in Advances from Affiliates, Net	(485)	(130,914)	112,246
Retirement of Long-term Debt – Nonaffiliated	-	-	(30,000)
Principal Payments for Capital Lease Obligations	(1,674)	(749)	(806)
Dividends Paid on Common Stock	(21,000)	(19,500)	(14,000)
Other Financing Activities	15	276	143
Net Cash Flows from (Used for) Financing Activities	(23,144)	8,405	67,583
Net Decrease in Cash and Cash Equivalents	(213)	(152)	(81)
Cash and Cash Equivalents at Beginning of Period	494	646	727
Cash and Cash Equivalents at End of Period	$ 281	$ 494	$ 646
SUPPLEMENTARY INFORMATION			
Cash Paid for Interest, Net of Capitalized Amounts	$ 35,838	$ 37,402	$ 28,602
Net Cash Paid (Received) for Income Taxes	(16,700)	(8,713)	3,554
Noncash Acquisitions Under Capital Leases	4,202	829	544
Construction Expenditures Included in Accounts Payable at December 31,	3,411	5,451	9,662
SIA Refund Included in Accounts Payable at December 31,	-	-	18,526

See Notes to Financial Statements.

INDEX OF NOTES TO FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

As a public utility, KPCo engages in the generation and purchase of electric power, and the subsequent sale, transmission and distribution of that power to 174,000 retail customers in its service territory in eastern Kentucky. KPCo also sells power at wholesale to municipalities.

Originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975, 1979 (twice) and 1980, the Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. It establishes an allocation method for generating capacity among its members based on relative peak demands and generating reserves through the payment of capacity charges and the receipt of capacity revenues. AEP Power Pool members are compensated for their costs of energy delivered to the AEP Power Pool and charged for energy received from the AEP Power Pool. The capacity reserve relationship of the AEP Power Pool members changes as generating assets are added, retired or sold and relative peak demand changes. 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 MLR, which determines each member's percentage share of revenues and costs.

In December 2010, each member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 1, 2014 or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. This decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If KPCo experiences decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and is unable to recover the change in revenues and costs through rates, prices or additional sales, it would have an adverse impact on future net income and cash flows.

The AEP East companies are parties to a Transmission Agreement defining how they share the costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The impacts of the new Transmission Agreement will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

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

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

The FERC regulates wholesale power markets, wholesale power transactions and wholesale transmission operations and rates. KPCo's wholesale power transactions are generally market-based. 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 has entered into wholesale power supply contracts with various municipalities that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually.

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

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

Accounting for the Effects of Cost-Based Regulation

As a rate-regulated electric public utility company, KPCo's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," KPCo records regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) 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, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Inventory

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

Accounts Receivable

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

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

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for KPCo. See "Sale of Receivables – AEP Credit" section of Note 11 for additional information.

Allowance for Uncollectible Accounts

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

Concentrations of Credit Risk and Significant Customers

KPCo does not have any significant customers that comprise 10% or more of its Operating Revenues as of December 31, 2010.

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

Emission Allowances

KPCo records emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. KPCo follows the inventory model for these allowances. Allowances expected to be consumed within one year are reported in Materials and Supplies. Allowances with expected consumption beyond one year are included in Deferred Charges and Other Noncurrent Assets. These allowances are consumed in the production of energy and are recorded in Fuel and Other Consumables Used for Electric Generation at an average cost. Allowances held for speculation are included in Prepayments and Other Current Assets. The purchases and sales of allowances are reported in the Operating Activities section of the Statements of Cash Flows. The net margin on sales of emission allowances is included in Electric Generation, Transmission and Distribution Revenues for nonaffiliated transactions and in Sales to AEP Affiliates Revenues for affiliated transactions because of its integral nature to the production process of energy and KPCo's revenue optimization strategy for operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets.

Property, Plant and Equipment

Electric utility property, plant and equipment are stated at original 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 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 take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain the plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under the accounting guidance for "Impairment or Disposal of Long-lived Assets."

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

Allowance for Funds Used During Construction (AFUDC)

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. KPCo records the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable and Accounts Payable approximate fair value because of the short-term maturity of these instruments.

Fair Value Measurements of Assets and Liabilities

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

For commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. Management verifies price curves using these broker quotes and classifies these fair values within Level 2 when substantially all of the fair value can be corroborated. Management typically obtains multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, the quoted bid and ask prices are averaged. In certain circumstances, a broker quote may be discarded if it is a clear outlier. Management uses a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated, these locations are included within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. 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 as Level 3.

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

Assets in the benefits trust are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	**United States Government**	**Corporate Debt**	**State and Local Government**
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. Fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are 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 KPSC's review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the KPSC. On a routine basis, the KPSC reviews and/or audits KPCo's fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, KPCo adjusts its FAC deferrals and records a provision for estimated refunds to recognize these probable outcomes. Changes in fuel costs, including purchased power are reflected in rates in a timely manner through the FAC. A portion of profits from off-system sales are shared with customers through the FAC.

Revenue Recognition

Regulatory Accounting

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

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

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 their customers. Generally, these power sales and purchases are reported on a net basis in Revenues in the Statements of Income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on the Statements of Income. Other RTOs do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

Physical energy purchases arising from non-derivative contracts are accounted for on a gross basis in Purchased Electricity for Resale on the Statements of Income. Energy purchases arising from non-trading derivative contracts are recorded based on the transaction's economic substance. Purchases under non-trading derivatives used to serve accrual based obligations are recorded in Purchased Electricity for Resale on the Statements of Income. All other non-trading derivative purchases are recorded net in revenues.

In general, KPCo records expenses 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, as well as 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 derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). KPCo initially records the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, KPCo subsequently reclassifies the gain or loss on the hedge from 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 "Accounting for Cash Flow Hedging Strategies" section of Note 7.

Maintenance

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

Income Taxes and Investment Tax Credits

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

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

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

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

Excise Taxes

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

Debt

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

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

Investments Held in Trust for Future Liabilities

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

Benefit Plans

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

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

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

The target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0 %	35.0 %	40.0 %
International and Global Equity	10.0 %	15.0 %	20.0 %
Fixed Income	35.0 %	39.0 %	45.0 %
Real Estate	4.0 %	5.0 %	6.0 %
Other Investments	1.0 %	5.0 %	7.0 %
Cash	0.5 %	1.0 %	3.0 %

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0 %	66.0 %	71.0 %
Fixed Income	29.0 %	32.0 %	37.0 %
Cash	1.0 %	2.0 %	4.0 %

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

For equity investments, the limits are as follows:

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

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

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers the following limitations apply:

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

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

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

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

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

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

Comprehensive Income (Loss)

Comprehensive income (loss) is defined as the change in equity (net assets) of a business enterprise during a period from transactions and other events and circumstances from nonowner sources. It includes all changes in equity during a period except those resulting from investments by owners and distributions to owners. 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. KPCo's components of AOCI as of December 31, 2010 and 2009 are shown in the following table:

	December 31,	
Components	**2010**	**2009**
	(in thousands)	
Cash Flow Hedges, Net of Tax	$ (451)	$ (601)

Earnings Per Share (EPS)

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

Subsequent Events

Management reviewed subsequent events through February 25, 2011, the date that KPCo's 2010 annual report was issued.

Adjustments to Sale of Receivables Disclosure

In the "Sale of Receivables – AEP Credit" section of Note 11, the disclosure was expanded for KPCo to reflect certain prior period amounts related to the sale of receivables that were not previously disclosed. These omissions were not material to the disclosure and had no impact on KPCo's previously reported net income, changes in shareholder's equity, financial position or cash flows.

Adjustments to Benefit Plans Footnote

In Note 5 – Benefit Plans, the disclosure was expanded to reflect disclosure requirements based upon KPCo's participation in the AEP System. These omissions were not material to the financial statements and had no impact on KPCo's previously reported net income, changes in shareholder's equity, financial position or cash flows.

2. RATE MATTERS

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

Kentucky Base Rate Filing

In December 2009, KPCo filed a base rate case with the KPSC to increase base revenues by $124 million annually based on an 11.75% return on common equity. The base rate case also requested recovery of deferred storm restoration expenses over a three-year period. In June 2010, the KPSC approved a settlement agreement to increase base revenues by $64 million annually based on a 10.5% return on common equity. The settlement agreement included recovery of $23 million of deferred storm restoration expenses over five years. New rates became effective with the first billing cycle of July 2010.

Validity of Nonstatutory Surcharges

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. 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. The KPSC filed for a discretionary review of the related Duke Energy case with the Kentucky Supreme Court. In October 2010, the Kentucky Supreme Court ruled that as long as rates established by a utility are fair, just and reasonable, the KPSC has broad ratemaking power to allow recovery of costs outside of a general rate case, even without a statute specifically authorizing recovery of such costs.

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 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 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $220 million from 2004 through 2006 when the SECA rates terminated. KPCo's portion of recognized gross SECA revenues was $17 million.

In 2006, a FERC Administrative Law Judge (ALJ) issued an initial decision finding that the SECA rates charged were unfair, unjust and discriminatory and that new compliance filings and refunds should be made. The ALJ also found that any unpaid SECA rates must be paid in the recommended reduced amount.

AEP filed briefs jointly with other affected companies asking the FERC to reverse the decision. In May 2010, the FERC issued an order that generally supports AEP's position and requires a compliance filing to be filed with the FERC by August 2010. In June 2010, AEP and other affected companies filed a joint request for rehearing with the FERC.

The AEP East companies provided reserves for net refunds for SECA settlements totaling $44 million applicable to the $220 million of SECA revenues collected. KPCo provided a reserve of $3.3 million.

Settlements approved by the FERC consumed $10 million of the reserve for refunds applicable to $112 million of SECA revenue. In December 2010, the FERC issued an order approving a settlement agreement resulting in the collection of $2 million of previously deemed uncollectible SECA revenue. Therefore, the AEP East companies reduced their reserves for net refunds for SECA settlements by $2 million. The balance in the reserve for future settlements as of December 31, 2010 was $32 million. KPCo's portion of the reserve balance at December 31, 2010 was $2.4 million.

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $3 million. KPCo's portion of the potential refund payments and potential payments to be received are $1.5 million and $800 thousand, respectively. A decision is pending from the FERC.

Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

The AEP East companies are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. 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, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs generally on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. In October 2010, the FERC approved a settlement agreement for the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years.

PJM Transmission Formula Rate Filing

AEP filed an application with the FERC in July 2008 to increase its open access transmission tariff (OATT) rates for wholesale transmission service within PJM. The filing sought to implement a formula rate allowing annual adjustments reflecting future changes in the AEP East companies' cost of service. The FERC issued an order conditionally accepting AEP's proposed formula rate and delayed the requested October 2008 effective date for five months. AEP began settlement discussions with the intervenors and the FERC staff which resulted in a settlement that was filed with the FERC in April 2010.

In October 2010, a settlement agreement was approved by the FERC which resulted in a $51 million annual increase beginning in April 2009 for service as of March 2009, of which approximately $7 million is being collected from nonaffiliated customers within PJM. Prior to November 2010, the remaining $44 million was billed to the AEP East companies and was generally offset by compensation from PJM for use of the AEP East companies' transmission facilities so that net income was not directly affected. Beginning in November 2010, AEP East companies, KGPCo and WPCo, which are parties to the modified TA, allocate revenue and expenses on different methodologies and will affect net income. See "Modification of the Transmission Agreement" above.

The settlement also results in an additional $30 million increase for the first annual update of the formula rate, beginning in August 2009 for service as of July 2009. Approximately $4 million of the increase will be collected from nonaffiliated customers within PJM with the remaining $26 million being billed to the AEP East companies.

Under the formula, an annual update will be filed to be effective July 2010 and each year thereafter. Also, beginning with the July 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. In May 2010, the second annual update was filed with the FERC to decrease the revenue requirement by $58 million for service as of July 2010. Approximately $8 million of the decrease will be refunded to nonaffiliated customers within PJM.

PJM/MISO Market Flow Calculation Settlement Adjustments

During 2009, an analysis conducted by MISO and PJM discovered several instances of unaccounted for power flows on numerous coordinated flowgates. These flows affected the settlement data for congestion revenues and expenses and dated back to the start of the MISO market in 2005. In January 2011, PJM and MISO reached a settlement agreement where the parties agreed to net various issues to zero. This settlement was filed with the FERC in January 2011. PJM and MISO are currently awaiting final approval from the FERC.

Transmission Agreement (TA)

Certain transmission facilities placed in service in 1998 were inadvertently excluded from the AEP East companies' TA calculation prior to January 2009. The excluded equipment was KPCo's Inez Station which had been determined as eligible equipment for inclusion in the TA in 1995 by the AEP TA transmission committee. The amount involved was $7 million annually. In June 2010, the KPSC approved a settlement agreement in KPCo's base rate filing which set new base rates effective July 2010 and excluded consideration of this issue.

3. EFFECTS OF REGULATION

Regulatory assets and liabilities are comprised of the following items:

Regulatory Assets:	December 31, 2010	December 31, 2009	Remaining Recovery Period
	(in thousands)		
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Not Earning a Return			
Storm Related Costs	$ - (a)	$ 24,355	
Total Regulatory Assets Not Yet Being Recovered	-	24,355	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
RTO Formation/Integration Costs	1,373	1,538	9 years
Unamortized Loss on Reacquired Debt	737	771	22 years
Regulatory Assets Currently Not Earning a Return			
Income Taxes, Net	123,789	114,131	23 years
Pension and OPEB Funded Status	58,853	56,848	13 years
Storm Related Costs	21,143 (a)	-	5 years
Postemployment Benefits	6,456	7,077	4 years
Other Regulatory Assets Being Recovered	1,242	1,354	various
Total Regulatory Assets Being Recovered	213,593	181,719	
Total Noncurrent Regulatory Assets	$ 213,593	$ 206,074	

Regulatory Liabilities:	December 31, 2010	December 31, 2009	Remaining Refund Period
	(in thousands)		
Current Regulatory Liability			
Over-recovered Fuel Costs - does not pay a return	$ 864	$ 1,787	1 year
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	27,975	24,979	(b)
Regulatory Liabilities Currently Not Paying a Return			
Unrealized Gain on Forward Commitments	5,844	8,977	5 years
Deferred Investment Tax Credits	993	1,697	10 years
Other Regulatory Liabilities Being Paid	179	25	various
Total Regulatory Liabilities Being Paid	34,991	35,678	
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 34,991	$ 35,678	

(a) Recovery of regulatory asset was granted during 2010.
(b) Relieved as removal costs are incurred.

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.

COMMITMENTS

KPCo has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, KPCo contractually commits to third-party construction vendors for certain material purchases and other construction services. Management forecasts approximately $86 million of construction expenditures excluding AFUDC for 2011. KPCo also purchases fuel, materials, supplies, services and property, plant and equipment under contract as part of its normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes KPCo's actual contractual commitments at December 31, 2010:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 181.9	$ 188.7	$ -	$ -	$ 370.6
Energy and Capacity Purchase Contracts (b)	0.9	0.4	0.1	-	1.4
Total	$ 182.8	$ 189.1	$ 0.1	$ -	$ 372.0

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

(b) Represents contractual commitments for energy and capacity purchase contracts.

GUARANTEES

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

Indemnifications and Other Guarantees

Contracts

KPCo enters into certain types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, exposure generally does not exceed the sale price. 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

Insurance and Potential Losses

KPCo maintains insurance coverage normal and customary for an 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 the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on net income, cash flows and 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 trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases 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 CO_2 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 Clean Air Act 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. In December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. Briefing is underway and the case will be heard in April 2011. Management believes the actions are without merit and intends to continue to defend against the claims.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of \$95 million to \$400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2010, there is one site for which KPCo has received an information request which could lead a Potentially Responsible Party designation. In the instance where KPCo has been named a defendant, disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

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

Defective Environmental Equipment

As part of the AEP System's continuing environmental investment program, management chose to retrofit wet flue gas desulfurization systems on one unit of the Big Sandy Plant utilizing the jet bubbling reactor (JBR) technology. Contracts for the project have been suspended. The retrofits on three units owned by KPCo's affiliates are operational. Due to unexpected operating results, management completed an extensive review of the design and manufacture of the JBR internal components. The review concluded that there were fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. Management initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. In 2010, management settled with Black & Veatch and resolved the issues involving the internal components and JBR vessel corrosion. These settlements resulted in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

5. BENEFIT PLANS

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

KPCo participates in an AEP sponsored qualified pension plan which covers substantially all of KPCo's employees. KPCo also participates in OPEB plans sponsored by AEP to provide medical and life insurance benefits for retired employees.

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

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.05 %	5.60 %	5.25 %	5.85 %
Rate of Compensation Increase	4.55 % (a)	4.20 % (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

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed 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 2010, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.55%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**
Discount Rate	5.60 %	6.00 %	6.00 %	5.85 %	6.10 %	6.20 %
Expected Return on Plan Assets	8.00 %	8.00 %	8.00 %	8.00 %	7.75 %	8.00 %
Rate of Compensation Increase	4.20 %	5.50 %	5.50 %	N/A	N/A	N/A

N/A Not Applicable

The expected return on plan assets for 2010 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

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

Health Care Trend Rates	**2010**	**2009**
Initial	8.00 %	6.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	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 thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 557	$ (449)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	6,689	(5,488)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. At December 31, 2010, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2010 and 2009

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

	Pension Plans		Other Postretirement Benefit Plans	
	2010	2009	2010	2009
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 108,511	$ 98,421	$ 50,826	$ 48,580
Service Cost	2,549	2,572	1,060	971
Interest Cost	5,900	5,861	2,953	2,866
Actuarial Loss	7,073	7,159	4,964	213
Plan Amendment Prior Service Credit	-	-	(679)	-
Benefit Payments	(10,441)	(5,502)	(3,163)	(2,525)
Participant Contributions	-	-	649	526
Medicare Subsidy	-	-	196	195
Benefit Obligation at December 31	$ 113,592	$ 108,511	$ 56,806	$ 50,826
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 81,637	$ 74,612	$ 35,553	$ 27,868
Actual Gain on Plan Assets	11,286	12,527	5,134	6,224
Company Contributions	6,184	-	2,593	3,460
Participant Contributions	-	-	649	526
Benefit Payments	(10,441)	(5,502)	(3,163)	(2,525)
Fair Value of Plan Assets at December 31	$ 88,666	$ 81,637	$ 40,766	$ 35,553
Underfunded Status at December 31	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)

Amounts Recognized on the Balance Sheets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
	(in thousands)			
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)
Underfunded Status	$ (24,926)	$ (26,874)	$ (16,040)	$ (15,273)

Amounts Included in Regulatory Assets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
Components	(in thousands)			
Net Actuarial Loss	$ 42,392	$ 41,003	$ 16,453	$ 14,519
Prior Service Cost (Credit)	429	579	(421)	-
Transition Obligation	-	-	-	747
Recorded as				
Regulatory Assets	$ 42,821	$ 41,582	$ 16,032	$ 15,266

Components of the change in amounts included in Regulatory Assets during the years ended December 31, 2010 and 2009 are as follows:

Components	Pension Plans 2010	Pension Plans 2009	Other Postretirement Benefit Plans 2010	Other Postretirement Benefit Plans 2009
	Years Ended December 31, (in thousands)			
Actuarial Loss (Gain) During the Year	$ 3,441	$ 2,316	$ 2,665	$ (3,856)
Prior Service Credit	-	-	(679)	-
Amortization of Actuarial Loss	(2,052)	(1,318)	(732)	(1,094)
Amortization of Prior Service Cost	(150)	(151)	-	-
Amortization of Transition Obligation	-	-	(488)	(488)
Change for the Year	$ 1,239	$ 847	$ 766	$ (5,438)

Pension and Other Postretirement Plans' Assets

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 31,021	$ 63	$ -	$ -	$ 31,084	35.1 %
International	9,259	-	-	-	9,259	10.4 %
Real Estate Investment Trusts	2,582	-	-	-	2,582	2.9 %
Common Collective Trust - International	-	3,738	-	-	3,738	4.2 %
Subtotal - Equities	42,862	3,801	-	-	46,663	52.6 %
Fixed Income:						
United States Government and Agency Securities	-	14,571	-	-	14,571	16.4 %
Corporate Debt	-	15,439	-	-	15,439	17.4 %
Foreign Debt	-	2,922	-	-	2,922	3.3 %
State and Local Government	-	522	-	-	522	0.6 %
Other - Asset Backed	-	1,175	-	-	1,175	1.3 %
Subtotal - Fixed Income	-	34,629	-	-	34,629	39.0 %
Real Estate	-	-	1,912	-	1,912	2.2 %
Alternative Investments	-	-	2,988	-	2,988	3.4 %
Securities Lending	-	5,845	-	-	5,845	6.6 %
Securities Lending Collateral (a)	-	-	-	(6,339)	(6,339)	(7.1)%
Cash and Cash Equivalents (b)	-	2,917	-	37	2,954	3.3 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	14	14	- %
Total	$ 42,862	$ 47,192	$ 4,900	$ (6,288)	$ 88,666	100.0 %

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

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

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2010	$ 2,171	$ 2,535	$ 4,706
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(259)	74	(185)
Relating to Assets Sold During the Period	-	24	24
Purchases and Sales	-	355	355
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 1,912	$ 2,988	$ 4,900

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2010:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 16,300	$ -	$ -	$ -	$ 16,300	40.0 %
International	6,153	-	-	-	6,153	15.1 %
Common Collective Trust - Global	-	3,203	-	-	3,203	7.9 %
Subtotal - Equities	22,453	3,203	-	-	25,656	63.0 %
Fixed Income:						
Common Collective Trust - Debt	-	1,332	-	-	1,332	3.3 %
United States Government and Agency Securities	-	2,615	-	-	2,615	6.4 %
Corporate Debt	-	3,071	-	-	3,071	7.5 %
Foreign Debt	-	692	-	-	692	1.7 %
State and Local Government	-	98	-	-	98	0.2 %
Other - Asset Backed	-	26	-	-	26	0.1 %
Subtotal - Fixed Income	-	7,834	-	-	7,834	19.2 %
Trust Owned Life Insurance:						
International Equities	-	1,369	-	-	1,369	3.3 %
United States Bonds	-	4,537	-	-	4,537	11.1 %
Cash and Cash Equivalents (a)	572	699	-	24	1,295	3.2 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	75	75	0.2 %
Total	$ 23,025	$ 17,642	$ -	$ 99	$ 40,766	100.0 %

(a) Amounts in "Other" column primarily represent foreign currency holdings.

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

The following table presents the classification of pension plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 29,256	$ -	$ -	$ -	$ 29,256	35.8 %
International	7,674	-	-	-	7,674	9.4 %
Real Estate Investment Trusts	2,080	-	-	-	2,080	2.6 %
Common Collective Trust - International	-	3,864	-	-	3,864	4.7 %
Subtotal - Equities	39,010	3,864	-	-	42,874	52.5 %
Fixed Income:						
United States Government and Agency Securities	-	5,585	-	-	5,585	6.9 %
Corporate Debt	-	19,930	-	-	19,930	24.4 %
Foreign Debt	-	4,100	-	-	4,100	5.0 %
State and Local Government	-	826	-	-	826	1.0 %
Other - Asset Backed	-	657	-	-	657	0.8 %
Subtotal - Fixed Income	-	31,098	-	-	31,098	38.1 %
Real Estate	-	-	2,171	-	2,171	2.7 %
Alternative Investments	-	-	2,535	-	2,535	3.1 %
Securities Lending	-	4,159	-	-	4,159	5.1 %
Securities Lending Collateral (a)	-	-	-	(4,697)	(4,697)	(5.8)%
Cash and Cash Equivalents (b)	-	2,773	-	97	2,870	3.5 %
Other - Pending Transactions and Accrued Income (c)	-	-	-	627	627	0.8 %
Total	$ 39,010	$ 41,894	$ 4,706	$ (3,973)	$ 81,637	100.0 %

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

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

	Real Estate	Alternative Investments	Total Level 3
		(in thousands)	
Balance as of January 1, 2009	$ 3,295	$ 2,554	$ 5,849
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(1,124)	(332)	(1,456)
Relating to Assets Sold During the Period	-	10	10
Purchases and Sales	-	303	303
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 2,171	$ 2,535	$ 4,706

The following table presents the classification of OPEB plan assets within the fair value hierarchy at December 31, 2009:

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in thousands)			
Equities:						
Domestic	$ 9,340	$ -	$ -	$ -	$ 9,340	26.2 %
International	10,190	-	-	-	10,190	28.7 %
Common Collective Trust - Global	-	2,532	-	-	2,532	7.1 %
Subtotal - Equities	19,530	2,532	-	-	22,062	62.0 %
Fixed Income:						
Common Collective Trust - Debt	-	1,032	-	-	1,032	2.9 %
United States Government and Agency Securities	-	1,139	-	-	1,139	3.2 %
Corporate Debt	-	3,847	-	-	3,847	10.8 %
Foreign Debt	-	873	-	-	873	2.4 %
State and Local Government	-	163	-	-	163	0.5 %
Other - Asset Backed	-	38	-	-	38	0.2 %
Subtotal - Fixed Income	-	7,092	-	-	7,092	20.0 %
Trust Owned Life Insurance:						
International Equities	-	2,025	-	-	2,025	5.7 %
United States Bonds	-	3,562	-	-	3,562	10.0 %
Cash and Cash Equivalents (a)	179	391	-	27	597	1.7 %
Other - Pending Transactions and Accrued Income (b)	-	-	-	215	215	0.6 %
Total	$ 19,709	$ 15,602	$ -	$ 242	$ 35,553	100.0 %

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

Determination of Pension Expense

The determination of pension expense or income is based on a market-related valuation of assets which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return 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, 2010	2009
	(in thousands)	
Qualified Pension Plan	$ 112,820	$ 107,206
Nonqualified Pension Plan	-	7
Total	$ 112,820	$ 107,213

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, 2010 and 2009 were as follows:

	Underfunded Pension Plans	
	2010	2009
	(in thousands)	
Projected Benefit Obligation	$ 113,592	$ 108,511
Accumulated Benefit Obligation	$ 112,820	$ 107,213
Fair Value of Plan Assets	88,666	81,637
Underfunded Accumulated Benefit Obligation	$ (24,154)	$ (25,576)

Estimated Future Benefit Payments and Contributions

KPCo expects contributions for the pension plan of $2.5 million and the OPEB plans of $2 million during 2011. The estimated contributions to the pension trust are at least the minimum amount required by ERISA and additional discretionary contributions may be made to maintain the funded status of the plan. The contributions to the OPEB plans are generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided in agreements with state regulatory authorities, plus the additional discretionary contribution of the Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from KPCo's assets. The payments include the participants' contributions to the plan for their share of the cost. 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 pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in thousands)	
2011	$ 6,503	$ 3,230	$ (220)
2012	6,697	3,444	(244)
2013	6,817	3,660	(276)
2014	7,121	3,875	(304)
2015	7,305	4,126	(333)
Years 2016 to 2020, in Total	41,440	24,149	(2,178)

Components of Net Periodic Benefit Cost

The following table provides the components of net periodic benefit cost for the years ended December 31, 2010, 2009 and 2008:

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2010	2009	2008	2010	2009	2008
	(in thousands)					
Service Cost	$ 2,549	$ 2,572	$ 2,508	$ 1,060	$ 971	$ 992
Interest Cost	5,900	5,861	5,712	2,953	2,866	2,966
Expected Return on Plan Assets	(7,654)	(7,684)	(7,883)	(2,841)	(2,187)	(3,031)
Amortization of Transition Obligation	-	-	-	488	488	488
Amortization of Prior Service Cost	150	151	153	-	-	-
Amortization of Net Actuarial Loss	2,052	1,318	505	732	1,094	203
Net Periodic Benefit Cost	2,997	2,218	995	2,392	3,232	1,618
Capitalized Portion	(1,064)	(825)	(454)	(849)	(1,202)	(738)
Net Periodic Benefit Cost Recognized as Expense	$ 1,933	$ 1,393	$ 541	$ 1,543	$ 2,030	$ 880

Estimated amounts expected to be amortized to net periodic benefit costs and the impact on the balance sheet during 2011 are shown in the following table:

Components	Pension Plans	Other Postretirement Benefit Plans
	(in thousands)	
Net Actuarial Loss	$ 2,846	$ 858
Prior Service Cost (Credit)	150	(35)
Total Estimated 2011 Amortization	$ 2,996	$ 823
Expected to be Recorded as		
Regulatory Asset	$ 2,996	$ 823
Total	$ 2,996	$ 823

American Electric Power System Retirement Savings Plan

KPCo participates in an AEP sponsored defined contribution retirement savings plan, the American Electric Power System Retirement Savings Plan, for substantially all employees. This qualified plan offers participants an opportunity to contribute a portion of their pay, includes features under Section 401(k) of the Internal Revenue Code and provides for matching contributions. The matching contributions to the plan were 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 $1.4 million in 2010, $1.7 million in 2009 and $1.6 million in 2008.

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, credit risk and, to a lesser extent, foreign currency exchange risk. These risks represent the risk of loss that may impact KPCo due to changes in the underlying market prices or rates. AEPSC, on behalf of KPCo, manages these risks using derivative instruments.

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

The strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which AEPSC transacts on behalf of KPCo.

Risk Management Strategies

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

The following table represents the gross notional volume of KPCo's outstanding derivative contracts as of December 31, 2010 and 2009:

Notional Volume of Derivative Instruments

	Volume December 31, 2010	Volume December 31, 2009	Unit of Measure
	(in thousands)		
Commodity:			
Power	40,277	38,509	MWHs
Coal	3,280	2,230	Tons
Natural Gas	449	3,600	MMBtus
Heating Oil and Gasoline	274	306	Gallons
Interest Rate	$ 2,008	$ 4,239	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

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

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

AEPSC, on behalf of KPCo, enters into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify exposure to interest rate risk by converting a portion of floating-rate debt to a fixed rate. AEPSC, on behalf of KPCo, also enters into interest rate derivative contracts to manage interest rate exposure related to 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.

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

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

The accounting guidance for "Derivatives and Hedging" requires recognition of all qualifying derivative instruments as either assets or liabilities on the balance 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 December 31, 2010 and 2009 balance sheets, KPCo netted $400 thousand and $800 thousand, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and $3.4 million and $6.4 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

The following tables represent the gross fair value impact of KPCo's derivative activity on the Balance Sheets as of December 31, 2010 and 2009:

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (a) (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 60,231	$ 418	$ -	$ (51,952)	$ 8,697
Long-term Risk Management Assets	16,978	148	-	(9,096)	8,030
Total Assets	77,209	566	-	(61,048)	16,727
Current Risk Management Liabilities	59,107	490	-	(53,638)	5,959
Long-term Risk Management Liabilities	13,265	146	-	(11,108)	2,303
Total Liabilities	72,372	636	-	(64,746)	8,262
Total MTM Derivative Contract Net Assets (Liabilities)	$ 4,837	$ (70)	$ -	$ 3,698	$ 8,465

Fair Value of Derivative Instruments
December 31, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate (a)**	**Other (a) (b)**	**Total**
		(in thousands)			
Current Risk Management Assets	$ 66,858	$ 748	$ -	$ (53,919)	$ 13,687
Long-term Risk Management Assets	26,571	-	-	(17,073)	9,498
Total Assets	93,429	748	-	(70,992)	23,185
Current Risk Management Liabilities	62,216	1,024	-	(58,050)	5,190
Long-term Risk Management Liabilities	23,879	16	-	(19,794)	4,101
Total Liabilities	86,095	1,040	-	(77,844)	9,291
Total MTM Derivative Contract Net Assets (Liabilities)	$ 7,334	$ (292)	$ -	$ 6,852	$ 13,894

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

(b) Amounts represent counterparty netting of risk management and hedging 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 years ended December 31, 2010 and 2009:

Amount of Gain (Loss) Recognized on
Risk Management Contracts
Years Ended December 31, 2010 and 2009

Location of Gain (Loss)	2010	2009
	(in thousands)	
Electric Generation, Transmission and Distribution Revenues	$ 10,188	$ 20,402
Sales to AEP Affiliates	(1,272)	(2,162)
Regulatory Assets (a)	(93)	-
Regulatory Liabilities (a)	(2,170)	(2,719)
Total Gain on Risk Management Contracts	$ 6,653	$ 15,521

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

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

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

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

Accounting for Fair Value Hedging Strategies

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

KPCo records realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on KPCo's Statements of Income. During 2010, 2009 and 2008, KPCo did not employ any fair value hedging strategies.

Accounting for Cash Flow Hedging Strategies

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

Realized gains and losses on derivative contracts for the purchase and sale of power, coal, natural gas and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on KPCo's Statements of Income, or in Regulatory Assets or Regulatory Liabilities on KPCo's Balance Sheets, depending on the specific nature of the risk being hedged. During 2010 and 2009, KPCo designated commodity derivatives as cash flow hedges.

KPCo reclassifies gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on its Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on the Statements of Income. During 2010 and 2009, KPCo designated cash flow hedging strategies for forecasted fuel purchases.

KPCo reclassifies gains and losses on interest rate derivative hedges related to debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2010, 2009 and 2008, KPCo did not employ any cash flow hedging strategies for interest rates.

The accumulated gains or losses related to foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on KPCo's Balance Sheets into Depreciation and Amortization expense on the Statements of Income over the depreciable lives of the fixed assets that were designated as the hedged items in qualifying foreign currency hedging relationships. During 2010, 2009 and 2008, KPCo did not employ any foreign currency hedging strategies.

During 2010, 2009 and 2008, hedge ineffectiveness was immaterial or nonexistent for all hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on KPCo's Balance Sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2010 and 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
Year Ended December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)
Changes in Fair Value Recognized in AOCI	(294)	-	(294)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	44	-	44
Purchased Electricity for Resale	390	-	390
Other Operation Expense	(14)	-	(14)
Maintenance Expense	(17)	-	(17)
Interest Expense	-	60	60
Property, Plant and Equipment	(19)	-	(19)
Balance in AOCI as of December 31, 2010	$ (48)	$ (403)	$ (451)

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2009

	Commodity	Interest Rate	Total
		(in thousands)	
Balance in AOCI as of December 31, 2008	$ 584	$ (525)	$ 59
Changes in Fair Value Recognized in AOCI	(152)	-	(152)
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Electric Generation, Transmission and Distribution Revenues	(1,564)	-	(1,564)
Fuel and Other Consumables Used for Electric Generation	(23)	-	(23)
Purchased Electricity for Resale	1,032	-	1,032
Interest Expense	-	62	62
Property, Plant and Equipment	(15)	-	(15)
Balance in AOCI as of December 31, 2009	$ (138)	$ (463)	$ (601)

During 2008, KPCo reclassified $320 thousand of gains from AOCI to net income.

Cash flow hedges included in Accumulated Other Comprehensive Income (Loss) on KPCo's Balance Sheets at December 31, 2010 and 2009 were:

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2010

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 81	$ -	$ 81
Hedging Liabilities (a)	(151)	-	(151)
AOCI Loss Net of Tax	(48)	(403)	(451)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(48)	(60)	(108)

Impact of Cash Flow Hedges on the Balance Sheet
December 31, 2009

	Commodity	Interest Rate	Total
		(in thousands)	
Hedging Assets (a)	$ 422	$ -	$ 422
Hedging Liabilities (a)	(714)	-	(714)
AOCI Loss Net of Tax	(138)	(463)	(601)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(127)	(60)	(187)

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

The actual amounts that KPCo reclassifies from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2010, 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 41 months.

Credit Risk

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

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

Collateral Triggering Events

Under the tariffs of the RTOs and Independent System Operators (ISOs) and a limited number of derivative and non-derivative contracts primarily related to competitive retail auction loads, KPCo is obligated to post an additional amount of collateral if certain credit ratings decline below investment grade. The amount of collateral required fluctuates based on market prices and total exposure. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these collateral triggering items in contracts. Management does not anticipate a downgrade below investment grade. The following table represents: (a) the aggregate fair value of such derivative contracts, (b) the amount of collateral KPCo would have been required to post for all derivative and non-derivative contracts if the credit ratings had declined below investment grade and (c) how much was attributable to RTO and ISO activities as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in thousands)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 1,368	$ 449
Amount of Collateral KPCo Would Have Been Required to Post	2,614	1,699
Amount Attributable to RTO and ISO Activities	2,608	1,601

In addition, a majority of KPCo's non-exchange traded commodity contracts contain cross-default provisions that, if triggered, would permit the counterparty to declare a default and require settlement of the outstanding payable. These cross-default provisions could be triggered if there was a non-performance event under outstanding debt in excess of $50 million. On an ongoing basis, AEP's risk management organization assesses the appropriateness of these cross-default provisions in the contracts. Management does not anticipate a non-performance event under these provisions. The following table represents: (a) the fair value of these derivative liabilities subject to cross-default provisions prior to consideration of contractual netting arrangements, (b) the amount this exposure has been reduced by cash collateral posted by KPCo and (c) if a cross-default provision would have been triggered, the settlement amount that would be required after considering KPCo's contractual netting arrangements as of December 31, 2010 and 2009:

	December 31, 2010	December 31, 2009
	(in thousands)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 15,930	$ 31,215
Amount of Cash Collateral Posted	1,376	628
Additional Settlement Liability if Cross Default Provision is Triggered	4,926	6,537

8. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

The book values and fair values of KPCo's Long-term Debt as of December 31, 2010 and 2009 are summarized in the following table:

	December 31, 2010		December 31, 2009	
	Book Value	Fair Value	Book Value	Fair Value
	(in thousands)			
Long-term Debt	$ 548,888	$ 628,623	$ 548,722	$ 599,909

Fair Value Measurements of Financial Assets and Liabilities

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

The following tables set forth, by level within the fair value hierarchy, KPCo's financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2010 and 2009. As required by the accounting guidance for "Fair Value Measurements and Disclosures," financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Management's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels. There have not been any significant changes in management's valuation techniques.

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2010

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a) (c)	$ 350	$ 73,753	$ 2,862	$ (61,018)	$ 15,947
Cash Flow Hedges:					
Commodity Hedges (a)	-	549	-	(468)	81
Dedesignated Risk Management Contracts (b)	-	-	-	699	699
Total Risk Management Assets	$ 350	$ 74,302	$ 2,862	$ (60,787)	$ 16,727
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a) (c)	$ 343	$ 69,996	$ 1,789	$ (64,017)	$ 8,111
Cash Flow Hedges:					
Commodity Hedges (a)	-	619	-	(468)	151
Total Risk Management Liabilities	$ 343	$ 70,615	$ 1,789	$ (64,485)	$ 8,262

Assets and Liabilities Measured at Fair Value on a Recurring Basis
December 31, 2009

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in thousands)		
Risk Management Assets					
Risk Management Commodity Contracts (a)	$ 472	$ 90,327	$ 2,592	$ (72,387)	$ 21,004
Cash Flow Hedges:					
Commodity Hedges (a)	-	748	-	(326)	422
Dedesignated Risk Management Contracts (b)	-	-	-	1,759	1,759
Total Risk Management Assets	$ 472	$ 91,075	$ 2,592	$ (70,954)	$ 23,185
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (a)	$ 533	$ 84,831	$ 693	$ (78,030)	$ 8,027
Cash Flow Hedges:					
Commodity Hedges (a)	-	1,040	-	(326)	714
DETM Assignment (d)	-	-	-	550	550
Total Risk Management Liabilities	$ 533	$ 85,871	$ 693	$ (77,806)	$ 9,291

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

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

(c) Substantially comprised of power contracts.

(d) See "Natural Gas Contracts with DETM" section of Note 12.

There have been no transfers between Level 1 and Level 2 during the year ended December 31, 2010.

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

Year Ended December 31, 2010	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2009	$ 1,899
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	361
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(1,496)
Transfers into Level 3 (d) (h)	232
Transfers out of Level 3 (e) (h)	(2,283)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	2,360
Balance as of December 31, 2010	$ 1,073

Year Ended December 31, 2009	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2008	$ 1,713
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(283)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets) Relating to Assets Still Held at the Reporting Date (a)	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(1,118)
Transfers in and/or out of Level 3 (f)	(103)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	1,690
Balance as of December 31, 2009	$ 1,899

Year Ended December 31, 2008	Net Risk Management Assets (Liabilities) (in thousands)
Balance as of December 31, 2007	$ (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 (f)	(192)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	1,967
Balance as of December 31, 2008	$ 1,713

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

9. INCOME TAXES

The details of income taxes as reported are as follows:

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Income Tax Expense (Credit):			
Current	$ 17,767	$ (40,140)	$ 4,674
Deferred	1,075	50,612	4,097
Deferred Investment Tax Credits	(704)	(822)	(875)
Total Income Taxes	$ 18,138	$ 9,650	$ 7,896

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

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Net Income	$ 35,282	$ 23,936	$ 24,531
Income Taxes	18,138	9,650	7,896
Pretax Income	$ 53,420	$ 33,586	$ 32,427
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 18,697	$ 11,755	$ 11,349
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	1,479	2,256	1,169
AFUDC	(720)	(626)	(872)
Removal Costs	(1,364)	(1,465)	(4,110)
Investment Tax Credits, Net	(704)	(822)	(875)
State and Local Income Taxes	2,069	(2,938)	1,072
Other	(1,319)	1,490	163
Total Income Taxes	$ 18,138	$ 9,650	$ 7,896
Effective Income Tax Rate	34.0 %	28.7 %	24.4 %

The following table shows elements of the net deferred tax liability and significant temporary differences:

	December 31, 2010	2009
	(in thousands)	
Deferred Tax Assets	$ 29,149	$ 29,427
Deferred Tax Liabilities	(351,734)	(341,896)
Net Deferred Tax Liabilities	$ (322,585)	$ (312,469)
Property-Related Temporary Differences	$ (239,361)	$ (234,969)
Amounts Due from Customers for Future Federal Income Taxes	(28,545)	(27,057)
Deferred State Income Taxes	(41,855)	(36,564)
Deferred Income Taxes on Other Comprehensive Loss	243	324
Accrued Pensions	9,285	9,994
Regulatory Assets	(23,129)	(22,694)
All Other, Net	777	(1,503)
Net Deferred Tax Liabilities	$ (322,585)	$ (312,469)

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 2001. 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 federal income taxes have been made for potential liabilities resulting from such matters. In addition, KPCo accrues interest on these uncertain tax positions. Management is not aware of any issues for open tax years that upon final resolution are expected to 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 previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and that the ultimate resolution of these audits will not materially impact net income. With few exceptions, KPCo is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

KPCo sustained federal, state and local net income tax operating losses in 2009 driven primarily by bonus depreciation, a change in tax accounting method related to units of property and other book versus tax temporary differences. As a result, KPCo accrued current federal, state and local income tax benefits in 2009. KPCo realized the federal cash flow in 2010 as there was sufficient capacity in prior periods to carry the consolidated federal net operating loss back. Most of KPCo's state and local jurisdictions do not provide for a net operating loss carry back. However it is anticipated that future taxable income will be sufficient to realize the tax benefit. As such, management has determined that a valuation allowance is unnecessary.

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

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

	Year Ended December 31,		
	2010	**2009**	**2008**
		(in thousands)	
Interest Expense	$ 439	$ 1,113	$ 303
Interest Income	-	-	1,863
Reversal of Prior Period Interest Expense	320	39	-

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

	December 31,	
	2010	**2009**
	(in thousands)	
Accrual for Receipt of Interest	$ 475	$ 416
Accrual for Payment of Interest and Penalties	566	722

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

	2010	2009	2008
		(in thousands)	
Balance at January 1,	$ 2,553	$ 3,345	$ 2,205
Increase - Tax Positions Taken During a Prior Period	970	2,178	-
Decrease - Tax Positions Taken During a Prior Period	(97)	(2,757)	(113)
Increase - Tax Positions Taken During the Current Year	-	-	1,301
Decrease - Tax Positions Taken During the Current Year	(202)	(141)	(144)
Increase - Settlements with Taxing Authorities	-	-	96
Decrease - Settlements with Taxing Authorities	(513)	-	-
Decrease - Lapse of the Applicable Statute of Limitations	-	(72)	-
Balance at December 31,	$ 2,711	$ 2,553	$ 3,345

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $184 thousand, $528 thousand and $881 thousand for 2010, 2009 and 2008, 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

The Economic Stimulus Act of 2008 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 KPCo's net income or financial condition, but provided a cash flow benefit of approximately $10 million.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by KPCo in March 2010. This reduction, which was offset by recording net tax regulatory assets, did not materially affect KPCo's net income, cash flows or financial condition for the year ended December 31, 2010.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on KPCo's net income or financial condition but had a favorable impact on cash flows of approximately $8 million in 2010.

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on KPCo's net income or financial condition. However, the bonus depreciation contributed to AEP's 2009 federal net operating tax loss and resulted in a 2010 cash flow benefit to KPCo of approximately $20 million.

State Tax Legislation

Michigan Senate Bill 0094 (MBT Act), effective January 1, 2008, provided a comprehensive restructuring of Michigan's principal business tax. The law replaced the Michigan Single Business Tax. 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 law also includes significant credits for engaging in Michigan-based activity.

In March 2008, legislation was signed 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:

Lease Rental Costs	2010	2009	2008
		Years Ended December 31, (in thousands)	
Net Lease Expense on Operating Leases	$ 836	$ 1,948	$ 2,250
Amortization of Capital Leases	1,673	746	971
Interest on Capital Leases	304	53	102
Total Lease Rental Costs	$ 2,813	$ 2,747	$ 3,323

The following table shows the property, plant and equipment under capital leases and related obligations recorded on KPCo's Balance Sheets. Capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on KPCo's Balance Sheets.

	December 31, 2010	December 31, 2009
	(in thousands)	
Property, Plant and Equipment Under Capital Leases		
Generation	$ 683	$ 504
Other Property, Plant and Equipment	6,511	2,876
Total Property, Plant and Equipment Under Capital Leases	7,194	3,380
Accumulated Amortization	1,781	1,627
Net Property, Plant and Equipment Under Capital Leases	$ 5,413	$ 1,753
Obligations Under Capital Leases		
Noncurrent Liability	$ 3,569	$ 1,113
Liability Due Within One Year	1,844	640
Total Obligations Under Capital Leases	$ 5,413	$ 1,753

Future minimum lease payments consisted of the following at December 31, 2010:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2011	$ 2,088	$ 791
2012	1,533	771
2013	1,284	728
2014	351	529
2015	300	399
Later Years	472	896
Total Future Minimum Lease Payments	$ 6,028	$ 4,114
Less Estimated Interest Element	615	
Estimated Present Value of Future Minimum Lease Payments	$ 5,413	

Master Lease Agreements

KPCo leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Certain assets were not included in the refinancing, but the assets will be purchased or refinanced in 2011. In addition, certain operating leases that were previously under lease with GE are now recorded as capital leases after the refinancing. The amounts refinanced for KPCo are as follows:

Leases Refinanced with GE	KPCo
	(in thousands)
Operating Lease to Operating Lease	$ 3,246
Capital Lease to Capital Lease	314
Operating Lease to Capital Lease	1,142

These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 84% of the unamortized balance of the equipment at the end of the lease term. If the fair 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 value and the unamortized balance, with the total guarantee not to exceed 84% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, KPCo is committed to pay the difference between the actual fair value and the residual value guarantee. At December 31, 2010, the maximum potential loss for these lease agreements was approximately $481 thousand ($312 thousand net of tax) assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair 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, 2010 and 2009:

Type of Debt	Maturity	Weighted Average Interest rate at December 31, 2010	Interest Rate Ranges at December 31, 2010	Interest Rate Ranges at December 31, 2009	Outstanding at December 31, 2010	Outstanding at December 31, 2009
					(in thousands)	
Senior Unsecured Notes	2017-2039	6.40%	5.625%-8.13%	5.625%-8.13%	$ 530,000	$ 530,000
Notes Payable - Affiliated	2015	5.25%	5.25%	5.25%	20,000	20,000
Unamortized Discount (net)					(1,112)	(1,278)
Total Long-term Debt Outstanding					548,888	548,722
Less Portion Due Within One Year					-	-
Long-term Portion					$ 548,888	$ 548,722

Long-term debt outstanding at December 31, 2010 is payable as follows:

	2011	2012	2013	2014	2015	After 2015	Total
				(in thousands)			
Principal Amount	$ -	$ -	$ -	$ -	$ 20,000	$ 530,000	$ 550,000
Unamortized Discount							(1,112)
Total Long-term Debt Outstanding							$ 548,888

Dividend Restrictions

Federal Power Act

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

Leverage Restrictions

Pursuant to credit agreement leverage restrictions, at December 31, 2010, none of the retained earnings of KPCo have restrictions related to the payment of dividends.

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 December 31, 2010 and 2009 is 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, 2010 and 2009 are described in the following table:

Year	Maximum Borrowings from Utility Money Pool	Maximum Loans to Utility Money Pool	Average Borrowings from Utility Money Pool	Average Loans to Utility Money Pool	Loans (Borrowings) to/from Utility Money Pool as of December 31,	Authorized Short-Term Borrowing Limit
			(in thousands)			
2010	$ 18,963	$ 69,599	$ 5,857	$ 25,995	$ 67,060	$ 250,000
2009	174,108	19,775	113,764	7,589	(485)	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, 2010, 2009 and 2008 are summarized in the following table:

Year Ended December 31,	Maximum Interest Rates for Funds Borrowed from Utility Money Pool	Minimum Interest Rates for Funds Borrowed from Utility Money Pool	Maximum Interest Rates for Funds Loaned to Utility Money Pool	Minimum Interest Rates for Funds Loaned to Utility Money Pool	Average Interest Rates for Funds Borrowed from Utility Money Pool	Average Interest Rates for Funds Loaned to Utility Money Pool
2010	0.55 %	0.09 %	0.53 %	0.09 %	0.38 %	0.31 %
2009	2.28 %	0.18 %	0.63 %	0.15 %	1.33 %	0.35 %
2008	5.47 %	2.28 %	- %	- %	3.42 %	- %

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, on KPCo's Statements of Income. For amounts borrowed from and advanced to the Utility Money Pool, KPCo incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Interest Expense	$ 10	$ 983	$ 1,893
Interest Income	49	18	-

Credit Facilities

In June 2010, KPCo and certain other companies in the AEP System reduced a $627 million credit agreement that matures in April 2011 to $478 million. Under the facility, letters of credit may be issued. As of December 31, 2010, there were no outstanding amounts for KPCo under the facility.

Sale of Receivables – AEP Credit

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

In July 2010, AEP Credit renewed its receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013.

KPCo's amount of accounts receivable and accrued unbilled revenues sold under the sale of receivables agreement was $63 million, $41 million and $56 million as of December 31, 2010, 2009 and 2008, respectively.

The fees paid by KPCo to AEP Credit for customer accounts receivable sold were $2 million, $2 million and $3 million for the years ended December 31, 2010, 2009 and 2008, respectively.

KPCo's proceeds on the sale of receivables to AEP Credit were $548 million, $500 million and $485 million as of December 31, 2010, 2009 and 2008, 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, defining how they share the costs and benefits associated with their generating plants. This sharing is based upon each company's MLR, 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 December 2010, each AEP Power Pool member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 2014 or such other date approved by the FERC. It is unknown at this time what will replace the Interconnection Agreement. 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 and 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.

CSW Operating Agreement

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

System Integration Agreement (SIA)

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

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

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

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, 2010, 2009 and 2008:

	Years Ended December 31,		
Related Party Revenues	**2010**	**2009**	**2008**
		(in thousands)	
Sales to AEP Power Pool	$ 57,777	$ 64,074	$ 62,642
Direct Sales to West Affiliates	711	454	3,521
Direct Sales to Transmission Companies	737	-	-
Natural Gas Contracts with AEPES	(435)	(1,823)	(133)
Other Revenues	1,215	(92)	219
Total Affiliated Revenues	$ 60,005	$ 62,613	$ 66,249

The following table shows the purchased power expense incurred from purchases from the pools and affiliates for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
Related Party Purchases	**2010**	**2009**	**2008**
		(in thousands)	
Purchases from AEP Power Pool	$ 107,199	$ 96,284	$ 127,669
Direct Purchases from West Affiliates	169	305	454
Purchases from AEGCo	101,032	101,731	106,256
Total Purchases	$ 208,400	$ 198,320	$ 234,379

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.

System Transmission Integration Agreement

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

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

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

APCo, CSPCo, I&M, KPCo and OPCo are parties to the TA, 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 MLR. The FERC approved a new TA effective November 2010. The impacts of the new TA will be phased-in for retail rates, adds KGPCo and WPCo as parties to the agreement and changes the allocation method.

KPCo's net credits as allocated under the TA during the years ended December 31, 2010, 2009 and 2008 were $8 million, $9 million and $2 million, respectively, and were recorded in Other Operation expense on KPCo's Statements of Income.

PSO, SWEPCo, TCC, TNC and AEPSC are parties to the TCA, originally dated January 1, 1997, as amended. 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

In 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, 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. The agreement between AEPSC and AEPES ended December 31, 2010, coinciding with the settlement of the remaining DETM contracts. KPCo's risk management liabilities related to DETM at December 31, 2009 was $550 thousand.

Fuel Agreement between OPCo and AEPES

OPCo and National Power Cooperative, Inc (NPC) have an agreement whereby OPCo operates a 500 MW gas plant owned by NPC (Mone Plant). AEPES entered into a fuel management agreement with OPCo and NPC to manage and procure fuel for the Mone Plant. The gas purchased by AEPES and used in generation is first sold to OPCo then allocated to the AEP East companies, who have an agreement to purchase 100% of the available generating capacity from the plant through May 2012. KPCo's related purchases of gas managed by AEPES were $195 thousand, $88 thousand and $257 thousand for the years ended December 31, 2010, 2009 and 2008, respectively. These purchases are reflected in Purchased Electricity for Resale on KPCo's Statements of Income.

Unit Power Agreements (UPA)

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

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

I&M Barging, Urea Transloading and Other Services

I&M provides barging, urea transloading and other transportation services to affiliates. Urea is a chemical used to control NO_x emissions at certain generation plants in the AEP System. KPCo recorded costs of $133 thousand, $112 thousand and $9 thousand in 2010, 2009 and 2008, respectively, for urea transloading provided by I&M. These costs were recorded as fuel expense or other 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 $368 thousand, $358 thousand and $1.2 million for the years ended December 31, 2010, 2009 and 2008, respectively.

Affiliate Coal Purchases

In 2008, OPCo entered into contracts to sell excess coal purchases to certain AEP subsidiaries through 2010. KPCo's purchases are reflected in Sales to AEP Affiliates on its Statements of Income. KPCo's realized and unrealized losses recorded for the years ended December 31, 2010, 2009 and 2008 were $837 thousand, $340 thousand and $36 thousand, respectively.

Affiliate Railcar Agreement

KPCo has an agreement providing for the use its of affiliates' leased or owned railcars when available. The agreement specifies that the company using the railcar will be billed, at cost, by the company furnishing the railcar. KPCo recorded these costs in Fuel on 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,	
Billing Company	**2010**	**2009**
	(in thousands)	
APCo	$ 399	$ 669
OPCo	245	13

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 ended in December 2008. KPCo recorded $4 million for the year ended December 31, 2008.

In January 2010, the AEP Power Pool began purchasing power from OVEC to serve off-system sales and retail sales through June 2010. Purchases serving off-system sales are reported net as a reduction in Electric Generation, Transmission and Distribution revenues and purchases serving retail sales are reported in Purchased Electricity for Resale expenses on KPCo's Statement of Income. KPCo recorded $1.4 million in revenue and $743 thousand in expense for the year ended December 31, 2010.

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, 2010, 2009 and 2008 as shown in the following table:

Companies	Years Ended December 31, 2010	2009	2008
	(in thousands)		
APCo to KPCo	$ 209	$ -	$ -
CSP to KPCo	433	-	-
I&M to KPCo	-	-	444
OPCo to KPCo	527	-	-

In addition, KPCo had aggregate affiliated sales and purchases of meters and transformers for the years ended December 31, 2010, 2009 and 2008 as shown in the following table:

	APCo	CSPCo	I&M	KGPCo	OPCo	PSO	SWEPCo	TCC	WPCo	Total
Sales					(in thousands)					
2010	$ 364	$ 9	$ 6	$ 23	$ 83	$ -	$ 2	$ -	$ -	$ 487
2009	505	23	64	7	133	3	8	-	1	744
2008	354	11	16	6	121	-	2	33	-	543
Purchases										
2010	139	-	7	-	139	-	3	-	-	288
2009	161	-	50	-	87	-	26	-	-	324
2008	112	-	15	-	95	-	-	-	-	222

The amounts above are recorded in Property, Plant and Equipment. Transfers are recorded at cost.

Global Borrowing Notes

AEP has an intercompany note in place with KPCo. The debt is reflected in Long-term Debt – Affiliated on KPCo's Balance Sheets. KPCo accrues interest for its share of the global borrowing and remits the interest to AEP. The accrued interest is reflected in Accrued Interest on KPCo's Balance Sheets. KPCo participates in the global borrowing arrangement.

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

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether KPCo is the primary beneficiary of a VIE, management considers factors such as equity at risk, the amount of the VIE's variability KPCo absorbs, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. Management believes that 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.

AEPSC provides certain managerial and professional services to KPCo and other subsidiaries. AEP is the sole equity owner of AEPSC. AEP management controls the activities of AEPSC. The costs of the services are based on a direct charge or on a prorated basis and billed to KPCo and other subsidiaries at AEPSC's cost. KPCo and other subsidiaries have not provided financial or other support outside the reimbursement of costs for services rendered. AEPSC finances its operations through cost reimbursement from other AEP subsidiaries. There are no other terms or arrangements between AEPSC and KPCo and other subsidiaries that could require additional financial support from KPCo and other 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 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 AEPSC due to its activity in AEPSC's cost reimbursement structure. However, KPCo does not have control over AEPSC. AEPSC is consolidated by AEP. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. Total billings from AEPSC for the years ended December 31, 2010, 2009 and 2008 were $37 million, $34 million and $46 million, respectively. The carrying amount of liabilities associated with AEPSC for the years ended December 31, 2010 and 2009 were $3 million and $4 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

AEGCo, a wholly-owned subsidiary of AEP, is consolidated by AEP. AEGCo owns a 50% ownership interest in Rockport Plant Unit 1 and leases a 50% interest in Rockport Plant Unit 2. AEGCo sells all the output from the Rockport Plant to I&M and KPCo. AEP guarantees all the debt obligations of AEGCo. KPCo is considered to have a significant interest in AEGCo due to its transactions. KPCo is exposed to losses to the extent it cannot recover the costs of AEGCo through its normal business operations. Due to AEP management's control over AEGCo, KPCo is not considered the primary beneficiary of AEGCo. In the event AEGCo would require financing or other support outside the billings to KPCo, this financing would be provided by AEP. Total billings from AEGCo for the years ended December 31, 2010, 2009 and 2008 were $101 million, $102 million and $106 million, respectively. The carrying amount of liabilities associated with AEGCo for the years ended December 31, 2010 and 2009 was $10 million and $9 million, respectively. Management estimates the maximum exposure of loss to be equal to the amount of such liability.

13. PROPERTY, PLANT AND EQUIPMENT

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:

2010	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)
Generation	$ 553,589	$ 200,199	3.8%	40-50	$ -	$ -	-	-
Transmission	444,303	148,466	1.7%	25-75	-	-	-	-
Distribution	590,606	171,092	3.5%	11-75	-	-	-	-
CWIP	34,093	(880)	N.M.	N.M.	-	-	-	-
Other	58,282	23,371	8.3%	N.M.	5,700	195	N.M.	N.M.
Total	$ 1,680,873	$ 542,248			$ 5,700	$ 195		

2009	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)
Generation	$ 547,378	$ 190,020	3.8%	40-50	$ -	$ -	-	-
Transmission	438,775	142,966	1.7%	25-75	-	-	-	-
Distribution	569,389	156,181	3.4%	11-75	-	-	-	-
CWIP	28,409	(3,767)	N.M.	N.M.	-	-	-	-
Other	53,504	23,218	9.7%	N.M.	5,498	188	N.M.	N.M.
Total	$ 1,637,455	$ 508,618			$ 5,498	$ 188		

2008	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate	Depreciable Life Ranges	Annual Composite Depreciation Rate	Depreciable Life Ranges
		(in years)		(in years)
Generation	3.5%	40-50	-	-
Transmission	1.6%	25-75	-	-
Distribution	3.4%	11-75	-	-
CWIP	N.M.	N.M.	-	-
Other	8.1%	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 the accounting guidance for "Asset Retirement and Environmental Obligations" for the retirement of asbestos removal. KPCo has identified, but not recognized, ARO liabilities related to electric transmission and distribution assets, as a result of certain easements on property on which assets are owned. Generally, such easements are perpetual and require only the retirement and removal of assets upon the cessation of the property's use. The retirement obligation is not estimable for such easements since KPCo plans to use its facilities indefinitely. The retirement obligation would only be recognized if and when KPCo abandons or ceases the use of specific easements, which is not expected.

The following is a reconciliation of the 2010 and 2009 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)			
2010	$ 3,506	$ 292	$ 823	$ (435)	$ -	$ 4,186
2009	3,275	297	-	(66)	-	3,506

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, 2010	2009	2008
		(in thousands)	
Allowance for Equity Funds Used During Construction	$ 768	$ 391	$ 1,012
Allowance for Borrowed Funds Used During Construction	594	394	1,701

14. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment on May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

KPCo recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. Management does not expect additional costs to be incurred related to this initiative.

Expense Allocation from AEPSC	Incurred	Settled	Adjustments	Remaining Balance at December 31, 2010
		(in thousands)		
$ 3,481	$ 8,175	$ 12,001	$ 1,363	$ 1,018

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the Statements of Income and Other Current Liabilities on the Balance Sheets.

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:

	2010 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in thousands)			
Total Revenues	$ 173,918	$ 136,972	$ 189,417 (b)	$ 183,365 (b)
Operating Income (Loss)	24,680	(2,831)(a)	33,326 (b)	33,680 (b)
Net Income (Loss)	9,491	(7,045)(a)	15,945 (b)	16,891 (b)

	2009 Quarterly Periods Ended			
	March 31	**June 30**	**September 30**	**December 31**
	(in thousands)			
Total Revenues	$ 178,433	$ 155,099	$ 152,153	$ 146,841
Operating Income	20,053	18,144	10,923	17,669
Net Income	9,454	6,208	1,309	6,965

(a) See Note 14 for discussion of expenses related to cost reduction initiatives recorded in the second quarter of 2010.
(b) See "Kentucky Base Rate Filing" section of Note 2 for discussion of new base rates in effect.

There were no significant events in 2009.

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

Form 60 Approved
OMB No. 1902-0215
Expires 01/31/2013

KPSC Case No. 99-149
Item No. 1
Attachment B

RECEIVED
MAY 13 2011
PUBLIC SERVICE COMMISSION

FERC FINANCIAL REPORT
FERC FORM No. 60: Annual Report of Centralized Service Companies

This report is mandatory under the Public Utility Holding Company Act of 2005, Section 1270, Section 309 of the Federal Power Act and 18 C.F.R. § 366.23. 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 this report to be of a confidential nature.

Exact Legal Name of Respondent (Company)	Year of Report
American Electric Power Service Corporation	Dec 31, 2010

FERC FORM NO. 60
ANNUAL REPORT FOR SERVICE COMPANIES

IDENTIFICATION

01 Exact Legal Name of Respondent American Electric Power Service Corporation	02 Year of Report Dec 31, 2010
03 Previous Name (If name changed during the year)	04 Date of Name Change / /
05 Address of Principal Office at End of Year (Street, City, State, Zip Code) 1 Riverside Plaza, Columbus, OH 43215	06 Name of Contact Person Kathy Messer
07 Title of Contact Person Accountant II	08 Address of Contact Person 1 Riverside Plaza, Columbus, OH 43215
09 Telephone Number of Contact Person (614) 716-2689	10 E-mail Address of Contact Person klmesser@aep.com
11 This Report is: (1) [X] An Original (2) [ ] A Resubmission	12 Resubmission Date (Month, Day, Year) / /
13 Date of Incorporation 12/17/1937	14 If Not Incorporated, Date of Organization / /

15 State or Sovereign Power Under Which Incorporated or Organized

NEW YORK

16 Name of Principal Holding Company Under Which Reporting Company is Organized.

American Electric Power

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.

17 Name of Signing Officer Andrew B. Reis	19 Signature of Signing Officer Andrew B. Reis	20 Date Signed (Month, Day, Year) 4/29/11
18 Title of Signing Officer Assistant Controller		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

List of Schedules and Accounts

1. Enter in Column (c) the terms "None" or "Not Applicable" as appropriate, where no information or amounts have been reported for certain pages.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule I - Comparative Balance Sheet

1. Give balance sheet of the Company as of December 31 of the current and prior year

Line No	Account Number (a)	Description (b)	Reference Page No (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
1		**Service Company Property**			
2	101	Service Company Property	103	236,905,752	204,057,857
3	101.1	Property Under Capital Leases	103	44,225,889	45,337,846
4	106	Completed Construction Not Classified		1,389,878	4,720,658
5	107	Construction Work In Progress	103	2,720,716	10,504 949
6		Total Property (Total Of Lines 2-5)		285,242,235	264,621,310
7	108	Less: Accumulated Provision for Depreciation of Service Company Property	104	139,199,523	135,155,231
8	111	Less: Accumulated Provision for Amortization of Service Company Property		9,079,264	8,841,267
9		Net Service Company Property (Total of Lines 6-8)		136,963,448	120,624,812
10		**Investments**			
11	123	Investment In Associate Companies	105		
12	124	Other Investments	105	171,085,315	152,810,183
13	128	Other Special Funds	105	2,020	2,020
14		Total Investments (Total of Lines 11-13)		171,087,335	152 812,203
15		**Current And Accrued Assets**			
16	131	Cash		14,058	15,470,640
17	134	Other Special Deposits		203,914	143,239
18	135	Working Funds		750,490	750,490
19	136	Temporary Cash Investments			
20	141	Notes Receivable			
21	142	Customer Accounts Receivable		850,765	44
22	143	Accounts Receivable		16 497,052	7,108,676
23	144	Less: Accumulated Provision for Uncollectible Accounts			
24	146	Accounts Receivable From Associate Companies	106	257,013,634	235,457 618
25	152	Fuel Stock Expenses Undistributed	107		
26	154	Materials And Supplies			
27	163	Stores Expense Undistributed	108		
28	165	Prepayments		2,470,007	2,394,146
29	171	Interest And Dividends Receivable		439	
30	172	Rents Receivable			
31	173	Accrued Revenues			
32	174	Miscellaneous Current and Accrued Assets			
33	175	Derivative Instrument Assets	109		
34	176	Derivative Instrument Assets -- Hedges			
35		Total Current and Accrued Assets (Total of Lines 16-34)		277,800,359	261,324,853
36		**Deferred Debits**			
37	181	Unamortized Debt Expense			
38	182.3	Other Regulatory Assets		684,302,979	643,184,964
39	183	Preliminary Survey And Investigation Charges			
40	184	Clearing Accounts			
41	185	Temporary Facilities			
42	186	Miscellaneous Deferred Debits		(584,116)	426,731
43	188	Research, Development, or Demonstration Expenditures	110		
44	189	Unamortized loss on reacquired debt	111		
45	190	Accumulated Deferred Income Taxes		174,438,522	182,340,972
46		Total Deferred Debits (Total of Lines 37-45)		858,157,385	825,952,667
47		TOTAL ASSETS AND OTHER DEBITS (TOTAL OF LINES 9, 14, 35 and 46)		1,444,008,527	1,360,714,535

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule I - Comparative Balance Sheet (continued)

Line No.	Account Number (a)	Description (b)	Reference Page No (c)	As of Dec 31 Current (d)	As of Dec 31 Prior (e)
48		**Proprietary Capital**			
49	201	Common Stock Issued	201	1,350,000	1,350,000
50	204	Preferred Stock Issued	201		
51	211	Miscellaneous Paid-In-Capital	201	8,222,656	8,222,656
52	215	Appropriated Retained Earnings	201		
53	216	Unappropriated Retained Earnings	201		
54	219	Accumulated Other Comprehensive Income	201		
55		Total Proprietary Capital (Total of Lines 49-54)		9,572,656	9,572,656
56		**Long-Term Debt**			
57	223	Advances From Associate Companies	202		
58	224	Other Long-Term Debt	202		
59	225	Unamortized Premium on Long-Term Debt			
60	226	Less: Unamortized Discount on Long-Term Debt-Debit			
61		Total Long-Term Debt (Total of Lines 57-60)			
62		Other Non-current Liabilities			
63	227	Obligations Under Capital Leases-Non-current		29,552,605	28,573,239
64	228.2	Accumulated Provision for Injuries and Damages		81,150	103,826
65	228.3	Accumulated Provision For Pensions and Benefits		566,083,945	737,537,751
66	230	Asset Retirement Obligations			
67		Total Other Non-current Liabilities (Total of Lines 63-66)		595,717,700	766,214,816
68		**Current and Accrued Liabilities**			
69	231	Notes Payable			
70	232	Accounts Payable		30,719,576	27,392,713
71	233	Notes Payable to Associate Companies	203	320,180,675	98,617,448
72	234	Accounts Payable to Associate Companies	203	134,680,446	165,275,701
73	236	Taxes Accrued		(14,231,563)	15,699,866
74	237	Interest Accrued		1,703,061	2,344,071
75	241	Tax Collections Payable		4,607,194	5,657,002
76	242	Miscellaneous Current and Accrued Liabilities	203	167,707,951	124,906,902
77	243	Obligations Under Capital Leases – Current		14,673,285	16,763,732
78	244	Derivative Instrument Liabilities			
79	245	Derivative Instrument Liabilities – Hedges			
80		Total Current and Accrued Liabilities (Total of Lines 69-79)		660,040,625	456,657,435
81		**Deferred Credits**			
82	253	Other Deferred Credits		2,406,255	2,648,577
83	254	Other Regulatory Liabilities		3,266,698	8,300,714
84	255	Accumulated Deferred Investment Tax Credits		393,814	444,622
85	257	Unamortized Gain on Reacquired Debt			
86	282	Accumulated deferred income taxes-Other property		7,870,028	11,333,176
87	283	Accumulated deferred income taxes-Other		164,740,751	105,542,539
88		Total Deferred Credits (Total of Lines 82-87)		178,677,546	128,269,628
89		**TOTAL LIABILITIES AND PROPRIETARY CAPITAL (TOTAL OF LINES 55, 61, 67, 80, AND 88)**		1,444,008,527	1,360,714,535

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule II - Service Company Property

1. Provide an explanation of Other Changes recorded in Column (f) considered material in a footnote.
2. Describe each construction work in progress on lines 18 through 30 in Column (b).

Line No.	Acct # (a)	Title of Account (b)	Balance at Beginning of Year (c)	Additions (d)	Retirements or Sales (e)	Other Changes (f)	Balance at End of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant	8,176,221	(24,470)	380,122		7,771,629
3	306	Leasehold Improvements	2,972,491	390,751			3,363,242
4	389	Land and Land Rights	7,391,128				7,391,128
5	390	Structures and Improvements	173,665,036	4,458,557	535,814		177,587,779
6	391	Office Furniture and Equipment	86,412,486	19,594,695	37,389,695		68,617,486
7	392	Transportation Equipment	564,478	24,904,452	242,632		25,226,298
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment	1,999,957	338,717	1,324,645		1,014,029
10	395	Laboratory Equipment	4,253,204	1,910,243	1,213,425		4,950,022
11	396	Power Operated Equipment					
12	397	Communications Equipment	13,047,213	2,638,912	5,613,225		10,072,900
13	398	Miscellaneous Equipment	3,380,717	294,288	688,479		2,986,526
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		**Total Service Company Property (Total of Lines 1-15)**	301,862,931	54,506,145	47,388,037		308,981,039
17	107	**Construction Work in Progress:**					
18		Capitalized Software	3,928,491	(3,880,270)			48,221
19		General and Misc. Equipment	1,579,343	(1,216,943)			362,400
20		Improvements to Office Buildings	4,997,115	(2,687,020)			2,310,095
21							
22							
23							
24							
25							
26							
27							
28							
29							
30							
31		**Total Account 107 (Total of Lines 14-30)**	10,504,949	(7,784,233)			2,720,716
32		**Total (Lines 16 and Line 31)**	312,367,880	46,721,912		0	311,701,755

Schedule Page: 103 Line No.: 32 Column: c

		Balance at Beginning of Year
101 Service Company Property	$	204,057,857
101.1 Property Under Capital Lease*		93,084,416
106 Completed Construction Not Classified		4,720,658
107 Construction Work In Progress		10,504,949
	$	312,367,880

* Provision for leased assets in the amount of $(47,746,570) included in FERC Account 101.1 is shown on page 104.

Schedule Page: 103 Line No.: 32 Column: f

There are no material other charges reported in Column (f).

Schedule Page: 103 Line No.: 32 Column: g

		Balance at End of Year
101 Service Company Property	$	236,905,752
101.1 Property Under Capital Lease*		70,685,409
106 Completed Construction Not Classified		1,389,878
107 Construction Work In Progress		2,720,716
	$	311,701,755

* Provision for leased assets in the amount of $(26,459,520) included in FERC Account 101.1 is shown on page 104.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule III – Accumulated Provision for Depreciation and Amortization of Service Company Property

1. Provide an explanation of Other Charges in Column (f) considered material in a footnote.

Line No.	Account Number (a)	Description (b)	Balance at Beginning of Year (c)	Additions Charged To Account 403-403.1 404-405 (d)	Retirements (e)	Other Changes Additions (Deductions) (f)	Balance at Close of Year (g)
1	301	Organization					
2	303	Miscellaneous Intangible Plant	7,035,541	357,684	380,122		7,013,103
3	306	Leasehold Improvements	2,220,609	283,421			2,504,030
4	389	Land and Land Rights					
5	390	Structures and Improvements	117,596,852	5,693,647	535,814	657,334	123,412,019
6	391	Office Furniture and Equipment	52,302,998	(868,664)	32,584,550	14,525,621	33,375,405
7	392	Transportation Equipment	125,580		146,714	253,502	232,368
8	393	Stores equipment					
9	394	Tools, Shop and Garage Equipment	872,751		985,927	431,905	318,729
10	395	Laboratory Equipment	1,216,766	83,589	731,594	302,753	871,514
11	396	Power Operated Equipment					
12	397	Communications Equipment	9,184,783		5,031,452	2,364,550	6,517,881
13	398	Miscellaneous Equipment	1,187,188	(311,690)	453,432	71,192	493,258
14	399	Other Tangible Property					
15	399.1	Asset Retirement Costs					
16		**Total**	191,743,068	5,237,987	40,849,605	18,606,857	174,738,307

Schedule Page: 104 Line No.: 16 Column: c

		Balance at Beginning of Year
101.1 Property Under Capital Lease*	$	47,746,570
108 Accumulated Provision for Depreciation of Service Company Property		135,155,231
111 Accumulated Provision for Amortization of Service Company Property		8,841,267
	$	191,743,068

* FERC Account 101.1 includes $47,746,570 of provision for leased assets.

Schedule Page: 104 Line No.: 16 Column: f

Other Changes:		Amount
Lease Additions and Transfers		18,645,748
Owned - Other Changes		(75,237)
Retirement Work In Progress		36,346
Other Miscellaneous		0
	$	18,606,857

Schedule Page: 104 Line No.: 16 Column: g

		Balance at End of Year
101.1 Property Under Capital Lease*	$	26,459,520
108 Accumulated Provision for Depreciation of Service Company Property		139,199,523
111 Accumulated Provision for Amortization of Service Company Property		9,079,264
	$	174,738,307

* FERC Account 101.1 includes $26,459,520 of provision for leased assets

Name of Respondent American Electric Power Service Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31. 2010

Schedule IV – Investments

1. For other investments (Account 124) and other special funds (Account128), in a footnote state each investment separately, with description including the name of issuing company, number of shares held or principal investment amount.
2. For temporary cash investments (Account 136), list each investment separately in a footnote
3. Investments less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	123	Investment In Associate Companies		
2	124	Other Investments	152,810,183	171,085,315
3	128	Other Special Funds	2,020	2,020
4	136	Temporary Cash Investments		
5		(Total of Lines 1-4)	152,812,203	171,087,335

Schedule Page: 105 Line No.: 2 Column: d

ACCOUNT DESCRIPTION	Balance at Beginning of Year	Balance at End of Year
Cash Surrender Value of Deferred Compensation Plan, issued by Northwest Mutual Life and John Hancock.	$ 14,561,077	$ 15,132,029
Cash Surrender Value of Umbrella Trust, issued by Prudential Life and Wells Fargo	98,973,396	110,096,970
Cash Surrender Value of Split Dollar Life Insurance, issued by Pacific Life.	38,029,308	44,978,743
Cash Surrender Value of Central and South West Supplemental Executive Retirement Plan, issued by The Newport Group	1,246,402	877,573
Total Other Investment	$ 152,810,183	$ 171,085,314

Schedule Page: 105 Line No.: 3 Column: d

ACCOUNT DESCRIPTION	Balance at Beginning of Year	Balance at End of Year
Health Spending Accounts Special Reserve	$ 2,020	$ 2,020

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule V – Accounts Receivable from Associate Companies

1. List the accounts receivable from each associate company.
2. If the service company has provided accommodation or convenience payments for associate companies, provide in a separate footnote a listing of total payments for each associate company.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	146	**Accounts Receivable From Associate Companies**		
2		**Associate Company:**		
3		AEP Appalachian Transmission Company, Inc	3,863	
4		AEP C&I Company LLC	3,342	2,595
5		AEP Coal, Inc.	22,975	3,386
6		AEP Credit, Inc	45,406	31,911
7		AEP Elmwood LLC	13,381	17,871
8		AEP Energy Partners. Inc.	451,963	536 391
9		AEP Energy Service Gas Holding Company	2,681	2 156
10		AEP Energy Services, Inc	111,279	86,688
11		AEP Fiber Venture, LLC		68
12		AEP Generating Company	690,087	1,092,171
13		AEP Indiana Michigan Transmission Company, Inc	212,904	
14		AEP Investments, Inc.	32,300	3,475
15		AEP Kentucky Coal, LLC	29,115	19,738
16		AEP Kentucky Transmission Company, Inc.	3,863	
17		AEP Nonutility Funding LLC	1,946	1.948
18		AEP Ohio Transmission Company, Inc	3,863	
19		AEP Oklahoma Transmission Company, Inc.	3,923	
20		AEP Pro Serv, Inc	39,138	103,925
21		AEP Resources, Inc.	25,255	8,383
22		AEP Retail Energy Partners LLC		41,959
23		AEP River Operations LLC	282,255	188,543
24		AEP Southwestern Transmission Company, Inc	5,553	
25		AEP System Pool	96.045	(1,331)
26		AEP T&D Services, LLC	571,792	523,015
27		AEP Texas C&I Retail GP, LLC	292	188
28		AEP Texas C&I Retail LP	20,695	3,560
29		AEP Texas Central Company	7,870,407	6,470,018
30		AEP Texas North Company	3,443,772	3,939,250
31		AEP Transmission Company, LLC	218,465	12,902,110
32		AEP Transmission Holding Company, LLC	317,442	381,292
33		AEP TX North Generation Company. LLC	4.075	1,806
34		AEP Utilities, Inc	348,415	124,309
35		AEP Utility Funding LLC	56,805	109,752
36		AEP West Virginia Transmission Company, Inc.	3,925	
37		AEP Wind Holding Company, LLC	45.336	52,037
38		AEPES US Gas Trading	1,849	3,236
39		American Electric Power Company	827,231	44,811,528

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule V – Accounts Receivable from Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	146	**Accounts Receivable From Associate Companies**		
2		**Associate Company:**		
3		Appalachian Power Company	98,861,015	91,125,601
4		Blackhawk Coal Company	1,292	3,188
5		Cardinal Operating Company	1,771,939	5,410,762
6		Cedar Coal Company	605	201
7		Central Appalachian Coal Company	720	201
8		Central Coal Company	721	200
9		Columbus Southern Power Company	48,482,765	20,283,238
10		Conesville Coal Preparation Company	17,220	26,203
11		CSW Energy Services, Inc	5,292	1,521
12		CSW Energy, Inc.	81,673	81,238
13		Desert Sky Wind Farm LP	33,605	18,653
14		Dolet Hills Lignite Co, LLC	206,331	195,074
15		Electric Transmission TX, LLC	2,913,036	2,426,103
16		Franklin Real Estate Company	349	1,009
17		Indiana Michigan Power Company	16,127,379	13,329,363
18		Kentucky Power Company	8,085,346	10,482,896
19		Kingsport Power Company	479,674	463,048
20		Mutual Energy SWEPCO L.P		30
21		Ohio Power Company	19,648,339	16,948,156
22		Oxbow Lignite Company, LLC		6,234
23		Public Service Company of Oklahoma	8,543,355	9,395,256
24		REP General Partner LLC	363	255
25		REP Holdco Inc	363	474
26		Snowcap Coal Company, Inc	2,045	2,836
27		Southern Appalachian Coal Company	605	200
28		Southwestern Electric Power Company	13,552,941	14,472,668
29		Trent Wind Farm LP	22,001	35,367
30		United Sciences Testing, Inc.	415,337	359,542
31		Wheeling Power Company	391,469	482,139
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39				
40	**Total**		**235,457,418**	**257,013,634**

Schedule Page: 106 Line No.: 3 Column: c

American Electric Power Service Corporation
Summary of Convenience Payments

Category	Total
Advertising Expense	4,577,919
AEP Foundation	20,000,000
Audit Fees	10,403,500
Bond Fees	2,925,982
Building Services	608,258
Construction Work in Progress	17,832,141
Current Accrued Liabilities	546,324
Energy Delivery Activity	38,757,836
Insurance and Employee Benefits	1,058,420
Investments	250,000
Leases and Rents	748,253
Maintenance	589,420
Management, Marketing & Distribution Services	765,817
Membership Dues and Donations	2,700,938
Miscellaneous	1,501,874
NERC Assessments	1,593,046
Office Supplies and Expenses	841,371
Outside Services	16,240,747
Relocation Services	2,327,688
Software Maintenance Agreement	496,358
Taxes	18,238,975
Telephone Services	3,917,392
Grand Total	146,922,258

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule VI -- Fuel Stock Expenses Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to fuel stock expenses during the year and indicate amount attributable to each associate company.
2. In a separate footnote, describe in a narrative the fuel functions performed by the service company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	152	Fuel Stock Expenses Undistributed			
2		Associate Company:			
3		AEP Appalachian Transmission Company, Inc		(1)	(1)
4		AEP C&I Company LLC	1		1
5		AEP Credit, Inc.	1	(1)	
6		AEP Energy Partners, Inc.	1	(10)	(9)
7		AEP Energy Services, Inc.	70	13	83
8		AEP Generating Company	5,884	2,363	8,247
9		AEP Indiana Michigan Transmission Company, Inc	3	(6)	(3)
10		AEP Investments, Inc.	2		2
11		AEP Kentucky Coal, LLC	(2,644)		(2,644)
12		AEP Ohio Transmission Company, Inc.	5	(5)	
13		AEP Oklahoma Transmission Company, Inc.	3		3
14		AEP Pro Serv, Inc	4	(2)	2
15		AEP Resources, Inc.	3	(1)	2
16		AEP T&D Services, LLC	(1)	(1)	(2)
17		AEP Texas Central Company	13,871	3,092	16,963
18		AEP Texas North Company	128,379	40,608	168,987
19		AEP Transmission Company, LLC	12	(5)	7
20		AEP Transmission Holding Company, LLC	58	(4)	54
21		AEP Utilities, Inc.	53	3	56
22		AEP Utility Funding LLC	138	30	168
23		AEP West Virginia Transmission Company, Inc.	1	(4)	(3)
24		AEP Wind Holding Company, LLC	37	6	43
25		American Electric Power Company	256	24	280
26		Appalachian Power Company	1,864,595	584,550	2,449,145
27		Cardinal Operating Company	374,892	118,063	492,955
28		Columbus Southern Power Company	1,152,363	330,045	1,482,408
29		Conesville Coal Preparation Company	6,438	1,595	8,033
30		CSW Energy Services, Inc.	1		1
31		CSW Energy, Inc	44	7	51
32		Dolet Hills Lignite Co, LLC		3,564	3,564
33		Electric Transmission America	1		1
34		Electric Transmission TX, LLC	169	(20)	149
35		Indiana Michigan Power Company	1,760,404	528,432	2,288,836
36		Kentucky Power Company	389,426	120,466	509,892
37		Kingsport Power Company	80	(3)	77
38		Ohio Power Company	3,692,005	1,103,720	4,795,725
39		PATH WV Transmission Company, LLC	22	(12)	10

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule VI – Fuel Stock Expenses Undistributed (continued)

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	152	Fuel Stock Expenses Undistributed			
2		Associate Company:			
3		Public Service Company of Oklahoma	766.894	234,454	1,001,348
4		Southwestern Electric Power Company	1,622,921	491,353	2,114,274
5		United Sciences Testing, Inc	8	(9)	(1)
6		Wheeling Power Company	757	72	829
7		Nonassociate companies	365.802	88,171	453,973
8		Less Amounts Billed	(12,142,959)	(3,650,547)	(15,793.506)
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40	**Total**				0

Schedule Page: 107 Line No.: 40 Column: e

Page 107, Footnote Regarding Fuel Functions of AEP Service Company

The fuel functions performed by AEP Service Company include:
The pricing of fuel consumed, the establishment of fuel inventory value, the recording and monitoring of accounting records for fuel purchased and fuel consumed including quantity and cost information.
The performance of laboratory analyses of coal and water samples for quality control purposes.
The coordination of fuel delivery to fossil fuel power plants which includes responding to power plant tests and monitoring the location of equipment such as barges and railcars that transport the fuel.
The coordination of preventive and corrective maintenance of railcars which includes inspections before and after maintenance is done, and the performance of routine safety inspections.
The oversight of affiliated coal operations which includes analysis of work, preparation of reports, site visits to monitor production, and the updating and creation of policies and procedures.
The provision of technical and economic analysis and investigation necessary to resolve problems
The production and distribution of specific Fuel filings which includes preparation of schedules, exhibits, and testimony.

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American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule VII – Stores Expense Undistributed

1. List the amount of labor in Column (c) and expenses in Column (d) incurred with respect to stores expense during the year and indicate amount attributable to each associate company.

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	163	Stores Expense Undistributed			
2		Associate Company:			
3		AEP Appalachian Transmission Company, Inc	683	49	732
4		AEP C&I Company LLC	254	25	279
5		AEP Credit, Inc	139	20	159
6		AEP Energy Partners, Inc	1,283	216	1,499
7		AEP Energy Services, Inc	12,913	671	13,584
8		AEP Generating Company	111,542	6,200	117,742
9		AEP Indiana Michigan Transmission Company, Inc.	1,914	190	2,104
10		AEP Investments, Inc	766	44	810
11		AEP Kentucky Transmission Company, Inc.	72	9	81
12		AEP Nonutility Funding LLC	40	2	42
13		AEP Ohio Transmission Company. Inc	2,196	184	2,380
14		AEP Oklahoma Transmission Company, Inc.	4,135	274	4,409
15		AEP Pro Serv, Inc	1,203	107	1,310
16		AEP Resources, Inc.	2,010	76	2,086
17		AEP Southwestern Transmission Company, Inc	21	2	23
18		AEP T&D Services. LLC	191	41	232
19		AEP Texas Central Company	928,088	48,755	976,843
20		AEP Texas North Company	409,041	16,821	425,862
21		AEP Transmission Company, LLC	579	84	663
22		AEP Transmission Holding Company, LLC	13,209	267	13,476
23		AEP TX North Generation Company, LLC	15	3	18
24		AEP Utilities, Inc	8,818	923	9,741
25		AEP Utility Funding LLC	20,161	1,094	21,255
26		AEP West Virginia Transmission Company, Inc.	821	77	898
27		AEP Wind Holding Company, LLC	6,895	352	7,247
28		American Electric Power Company	34,188	1,837	36,025
29		Appalachian Power Company	2,796,555	157,572	2,954,127
30		Cardinal Operating Company	383,626	18,899	402,525
31		Columbus Southern Power Company	1,079,366	101,380	1,180,746
32		Conesville Coal Preparation Company	5,356	731	6,087
33		CSW Energy Services, Inc	171	10	181
34		CSW Energy, Inc	9,113	513	9,626
35		Electric Transmission America	160	4	164
36		Electric Transmission TX, LLC	443,908	82,950	526,858
37		Indiana Michigan Power Company	1,501,849	97,193	1,599,042
38		Kentucky Power Company	449,010	27,455	476,465
39		Kingsport Power Company	31,203	2,176	33,379

Schedule VII -- Stores Expense Undistributed (continued)

Line No.	Account Number (a)	Title of Account (b)	Labor (c)	Expenses (d)	Total (e)
1	163	Stores Expense Undistributed			
2		Associate Company:			
3		Ohio Power Company	2,553,451	141,437	2,694,888
4		PATH WV Transmission Company, LLC	207,573	900	208,473
5		Public Service Company of Oklahoma	1,155,788	66,526	1,222,314
6		Southwestern Electric Power Company	1,665,124	79,195	1,744,319
7		United Sciences Testing, Inc.	1,541	211	1,752
8		Wheeling Power Company	35,113	2,793	37,906
9		Less Amounts Billed	(13,880,084)	(858,268)	(14,738,352)
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40	**Total**				

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule VIII - Miscellaneous Current and Accrued Assets

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	174	Miscellaneous Current and Accrued Assets		
2		Item List:		
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40	**Total**			

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule IX - Miscellaneous Deferred Debits

1. Provide detail of items in this account. Items less than $50,000 may be grouped, showing the number of items in each group.

Line No	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	186	**Miscellaneous Deferred Debits**		
2		**Items List:**		
3		Deferred Lease Assets - Non Taxable	298,501	(994,083)
4		Unamortized Credit Line Fees	72,710	396,606
5		Items less than $50,000 (2 items)	55,520	13,361
6				
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40	**Total**		**426,731**	**(584,116)**

Name of Respondent American Electric Power Service Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2010

Schedule X - Research, Development, or Demonstration Expenditures

1. Describe each material research, development, or demonstration project that incurred costs by the service corporation during the year. Items less than $50,000 may be grouped, showing the number of items in each group

Line No.	Account Number (a)	Title of Account (b)	Amount (c)
1	188	**Research, Development, or Demonstration Expenditures**	
2		**Project List:**	
3		Electric Power Research Institute (EPRI) Environmental Science	4,287,610
4		Electric Power Research Institute (EPRI) Nuclear Annual Research	1,308,570
5		Electric Power Research Institute (EPRI) Environmental Controls	1,209,731
6		Distribution Electric Power Research Institute (EPRI) Annual Portfolio	1,139,128
7		Clean Coal Power Initiative Round 3 Phase 1	1,030,753
8		Industrial Advisory Committee - Southern Company	1,010,430
9		EPRI Demonstration-IGCC (Integrated Gasification Combined Cycle) with CO2 Capture Storage	1,001,435
10		Electric Power Research Institute (EPRI) Annual Portfolio	843,108
11		Transmission Electric Power Research Institute (EPRI) Annual Portfolio	839,188
12		Electric Power Research Institute (EPRI) Demonstration-Post Combustion CO2 Capture & Storage	833,334
13		Distributed Energy Resources (DER) Program Management	429,339
14		Electric Power Research Institute (EPRI) Demo-Ion Transport Membrane for low cost Oxygen Production	337,212
15		Grid of the Future Test Bed	330,790
16		Corporate Technology Program Management	247,503
17		Electric Power Research Institute (EPRI) Renewable Annual Portfolio	240,968
18		Plug-in Hybrid Electric Vehicle(PHEV) Technology Future Strategies	231,584
19		Electric Power Research Institute (EPRI) Demo - Smart Grid	196,542
20		Coal Utilization Research Council	187,599
21		Ohio River Ecological Research Program	179,048
22		The National Electric Energy, Testing, Research, and Applications Center (NEETRAC) Membership	178,432
23		Broadband Power Line Carrier (BPL) Use for Data Transportation	177,196
24		Prism 2.0-Energy Economic Model Development	175,000
25		Micro-grid Test Bed/DOE (Department of Energy) Tests	166,387
26		Generation Asset Management - Program Management	155,502
27		Electric Power Research Institute (EPRI) Demo - Energy Efficiency	140,000
28		DTC (Dolan Technology Center) Walnut Maintenance	115,133
29		Transmission RD&D Program Management	114,183
30		CEA (Canadian Electric Association) Membership & Projects	107,721
31		Advanced Generation Program Management	101,450
32		Ash Pond Selective Catalytic Reduction (SCR) Ammonia Mitigation	97,500
33		Advanced Sensors - 765kv Substations - Data Integration	91,490
34		AEP OH (AEP Ohio) Interoperability Roadmap	88,428
35		Testing-WP91 Fittings & Piping	83,000
36		Advanced Cooling Technology	75,559
37		Enviromental Science & Controls Program Management	75,172
38		Improving Emission Offset Estimates	75,000
39		Renewable R&D Program Management	74,023

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American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule X - Research, Development, or Demonstration Expenditures (continued)

Line No.	Account Number (a)	Title of Account (b)	Amount (c)
1	188	**Research, Development, or Demonstration Expenditures**	
2		**Project List:**	
3		Oxidation Exfoliation-Stainless Steel Tubes	71,658
4		Phasor Technology: Planning & Operations Tools	69,864
5		Evaluation of Solid Sorbents as a Retrofit Technology for CO2 Capture from Coal-Fired Power Plants	67,172
6		WiFi-HAN (Home Area Network) PreDemo Qualification	66,257
7		PSerc (Power Systems Engineering Research Center)	57,694
8		ReXorce 250kW Heat Engine Test	53,005
9		GRIDSMRT-Solar Wind Energy Storage	51,941
10		AEP OH (AEP Ohio) Interoperability Testing	50,000
11		Soft Zone Effect-P91 Piping Components	50,000
12		International Electrotechnical Commission (IEC) 61850 Testing Project	50,000
13		77 Items under $50,000	1,032,731
14		Less Amount Billed	(19,595,370)
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40	**Total**		

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XI - Proprietary Capital

1. For miscellaneous paid-in capital (Account 211) and appropriate retained earnings (Account 215), classify amounts in each account, with a brief explanation, disclosing the general nature of transactions which give rise to the reported amounts.
2. For the unappropriated retained earnings (Account 216), in a footnote, give particulars concerning net income or (loss) during the year, distinguishing between compensation for the use of capital owed or net loss remaining from servicing nonassociates per the General Instructions of the Uniform System of Accounts. For dividends paid during the year in cash or otherwise, provide rate percentages, amount of dividend, date declared and date paid.

Line No.	Account Number (a)	Title of Account (b)	Description (c)	Amount (d)
1	201	Common Stock Issued	Number of Shares Authorized	20,000
2			Par or Stated Value per Share	100.00
3			Outstanding Number of Shares	13,500
4			Close of Period Amount	1,350,000
5		Preferred Stock Issued	Number of Shares Authorized	
6			Par or Stated Value per Share	
7			Outstanding Number of Shares	
8			Close of Period Amount	
9	211	Miscellaneous Paid-In Capital		8,222,656
10	215	Appropriated Retained Earnings		
11	219	Accumulated Other Comprehensive Income		
12	216	Unappropriated Retained Earnings	Balance at Beginning of Year	
13			Net Income or (Loss)	
14			Dividend Paid	
15			Balance at Close of Year	

Schedule Page: 201 Line No.: 9 Column: d

The Miscellaneous Paid-In Capital for $8,222,656 is made up of two capital contributions.

The first capital contribution of $99,500 represents the net investment of Central and South West Services, LP with AEPSC when the two service corporations combined as a result of the merger of Central and South West Corporation and American Electric Power in June of 2000.

The second capital contribution of $8,123,156 was due to an American Electric Power Company Inc. board resolution in April 2009 which transferred a parking garage to AEPSC. The resolution approved the contribution of the Marconi Street Unassigned Parking Garage to AEPSC as a capital contribution in the amount of the net book value of the property. The contribution of the unassigned garage to AEPSC was proposed to align its ownership with its primary user i.e. AEPSC.

Name of Respondent American Electric Power Service Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2010

Schedule XII – Long Term Debt

1. For the advances from associate companies (Account 223), describe in a footnote the advances on notes and advances on open accounts. Names of associate companies from which advances were received shall be shown under the class and series of obligation in Column (c).
2. For the deductions in Column (h), please give an explanation in a footnote.
3. For other long-term debt (Account 224), list the name of the creditor company or organization in Column (b).

Line No.	Account Number (a)	Title of Account (b)	Term of Obligation Class & Series of Obligation (c)	Date of Maturity (d)	Interest Rate (e)	Amount Authorized (f)	Balance at Beginning of Year (g)	Additions Deductions (h)	Balance at Close of Year (i)
1	223	Advances from Associate Companies							
2		Associate Company:							
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11									
12									
13		TOTAL							
14	224	Other Long-Term Debt							
15		List Creditor:							
16		No Long-Term Debt in 2010							
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27									
28		TOTAL							

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XIII – Current and Accrued Liabilities

1. Provide the balance of notes and accounts payable to each associate company (Accounts 233 and 234).
2. Give description and amount of miscellaneous current and accrued liabilities (Account 242). Items less than $50,000 may be grouped, showing the number of items in each group.

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
1	233	Notes Payable to Associates Companies		
2		AEP Utility Funding LLC	98,617,448	320,180,675
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24	234	Accounts Payable to Associate Companies	165,275,701	134,680,446
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31				
32				
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35				
36				
37				
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41	242	Miscellaneous Current and Accrued Liabilities	124,906,902	167,707,951
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43				
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45				
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48				
49				

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XIII – Current and Accrued Liabilities (continued)

Line No.	Account Number (a)	Title of Account (b)	Balance at Beginning of Year (c)	Balance at Close of Year (d)
50		(Total)	388,800,051	622,569,072

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
American Electric Power Service Corporation	(1) X An Original (2) _ A Resubmission	/ /	2010

FOOTNOTE DATA

Schedule Page: 203 Line No.: 2 Column: d

AEP Utility Funding Inc. is a financing subsidiary of American Electric Power, Inc. It provides a central account for regulated utility money pool balances to be consolidated within.

Schedule Page: 203 Line No.: 24 Column: d

Account 234 - Accounts Payable to Associate Companies	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
AEP Appalachian Transmission Company, Inc.	1,745	(0)
AEP C&I Company LLC	9	0
AEP Credit, Inc.	2	54
AEP Elmwood LLC	307	0
AEP Energy Partners, Inc.	630	3
AEP Energy Services, Inc.	62	(0)
AEP Generating Company	203	(0)
AEP Indiana Michigan Transmission Company, Inc.	1,745	(0)
AEP Kentucky Transmission Company, Inc.	1,745	0
AEP Ohio Transmission Company, Inc.	1,745	0
AEP Oklahoma Transmission Company, Inc.	1,745	0
AEP Pro Serv, Inc.	1,612	(0)
AEP River Oper Comm Consol	2	2
AEP River Operations LLC	25	7,242
AEP Southwestern Transmission Company, Inc.	1,745	0
AEP T&D Services, LLC	66,761	0
AEP Texas Central Company	5,466,872	1,292,931
AEP Texas North Company	1,623,909	214,676
AEP Transmission Company, LLC	0	83,726
AEP Utilities, Inc.	(1)	1,207,793
AEP West Virginia Transmission Company, Inc.	1,745	(0)
American Electric Power Company	1,401,111	3,304,166
Appalachian Power Company	14,754,166	13,553,295
Blackhawk Coal Company	0	5,040
Cardinal Operating Company	89,716	84,923
Columbus Southern Power Company	3,443,499	9,182,037
Conesville Coal Preparation Company	6	0
Desert Sky Wind Farm LP	0	54,523
Indiana Michigan Power Company	16,776,226	33,080,903
Kentucky Power Company	2,761,509	1,793,282
Kingsport Power Company	198,263	421,138
Ohio Power Company	109,521,263	61,085,144
Public Service Company of Oklahoma	4,114,954	5,243,820
Southwestern Electric Power Company	4,839,697	3,886,387
Trent Wind Farm LP	0	16,681
United Sciences Testing, Inc.	1,195	0
Wheeling Power Company	201,488	162,680
Total	$ 165,275,701	$ 134,680,446

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
American Electric Power Service Corporation	(1) X An Original (2) _ A Resubmission	/ /	2010

FOOTNOTE DATA

Schedule Page: 203 Line No.: 41 Column: d

ACCOUNT DESCRIPTION	BALANCE AT BEGINNING OF YEAR	BALANCE AT CLOSE OF YEAR
Account 242 - Miscellaneous Current and Accrued Liabilities		
Accrued Payroll	$ 7,452,207	$ 7,984,911
Control Cash Disbursements Account	10,681,671	1,237,659
Deferred Compensation Benefits	752,661	704,855
Employee Benefits	21,495,858	17,376,469
Incentive Pay	33,567,310	87,376,587
Lease Rent Holidays	458,430	694,240
Real and Personal Property Taxes	26,675	34,531
Rent on John E. Dolan Engineering Laboratory	396,935	353,063
Rent on Personal Property	182,570	195,460
Severance Pay	-	7,656,928
Accrued Professional Tax Services	-	20,165
Unclaimed Funds	-	187
Vacation Pay	48,509,955	42,947,838
Workers' Compensation	1,382,630	1,125,058
	$124,906,902	$ 167,707,951

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
American Electric Power Service Corporation	(1) X An Original (2) __ A Resubmission	/ /	2010

Schedule XIV- Notes to Financial Statements

1. Use the space below for important notes regarding the financial statements or any account thereof.
2. Furnish particulars as to any significant contingent assets or liabilities existing at the end of the year.
3. Furnish particulars as to any significant increase in services rendered or expenses incurred during the year
4. Furnish particulars as to any amounts recorded in Account 434, Extraordinary Income, or Account 435, Extraordinary Deductions.
5. Notes relating to financial statements shown elsewhere in this report may be indicated here by reference
6. Describe the annual statement supplied to each associate service company in support of the amount of interest on borrowed capital and compensation for use of capital billed during the calendar year. State the basis for billing of interest to each associate company. If a ratio, describe in detail how ratio is computed. If more than one ratio explain the calculation. Report the amount of interest borrowed and/or compensation for use of capital billed to each associate company.

Instruction 1

Notes regarding the financial statements are provided below:

NOTES TO FINANCIAL STATEMENTS

1. Organization and Summary of Significant Accounting Policies
2. Effects of Regulation
3. Commitments, Guarantees and Contingencies
4. Benefit Plans
5. Income Taxes
6. Leases
7. Financing Activities
8. Stock-Based Compensation
9. Related Party Transactions
10. Cost Reduction Initiatives

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

AEPSC is a wholly-owned subsidiary of AEP, a public utility holding company. AEPSC provides certain managerial and professional services including administrative and engineering services to affiliated companies in the AEP System and periodically to nonaffiliated companies. AEPSC acts as an agent on behalf of affiliated companies in the AEP System for certain contractual arrangements, such as purchases and sales of risk management assets and liabilities. The activity associated with the agency relationship is excluded from AEPSC's financial statements.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

AEPSC's intercompany service billings, which are AEPSC's fully allocated cost, including taxes, are regulated by the FERC under the 2005 Public Utility Holding Company Act and the Federal Power Act. The FERC also has jurisdiction over the issuances and acquisitions of securities of public utility subsidiaries, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. In addition, both the FERC and state regulatory commissions are permitted to review and audit the relevant books and records of companies within a public utility holding company system.

Accounting for the Effects of Cost-Based Regulation

As a cost-based regulated entity, AEPSC's financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate regulated. In accordance with accounting guidance for "Regulated Operations," regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) are recorded in accordance with regulatory actions to match expenses and revenues in cost-based rates. Regulatory assets are expected to be recovered in future periods through billings to client companies and regulatory liabilities are expected to reduce future billings. In the event that a portion of AEPSC's business no longer met those requirements, all amounts would be recoverable from affiliated companies. In the event AEPSC would require financing or other support outside the cost reimbursement billings, this financing would be provided by AEP. Costs charged to capitalized projects of AEPSC customers are included in the financial statements of AEPSC.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include but are not limited to the effects of regulation, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

Cash and Cash Equivalents include temporary cash investments with original maturities of three months or less.

Accounts Receivable

Accounts Receivable primarily includes receivables from affiliated companies for professional services rendered. AEPSC bills affiliated companies for services rendered on a monthly basis based on a work order system that is in accordance with the 2005 PUHCA. The affiliated companies generally remit these payments within 30 days.

Property and Equipment

Property is stated at original cost. Land, structures and structural improvements are generally subject to first mortgage liens. Depreciation is provided on a straight-line basis over the estimated useful lives of the property. The annual composite depreciation rate was 2.82% and 4.01% for the years ended December 31, 2010 and 2009, respectively.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under the accounting guidance for "Impairment or Disposal of Long-lived Assets."

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.

Deferred Compensation

Investments include the cash surrender value of trust owned life insurance policies held under a grantor trust to provide funds for nonqualified deferred compensation plans that AEPSC sponsors.

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.

Fair Value Measurements of Assets and Liabilities

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

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

Assets in the benefits trust are classified using the following methods. Equities are classified as Level 1 holdings if they are actively traded on exchanges. Items classified as Level 1 are investments in money market funds, fixed income and equity mutual funds and domestic equity securities. They are valued based on observable inputs primarily unadjusted quoted prices in active markets for identical assets. Fixed income securities do not trade on an exchange and do not have an official closing price. Pricing vendors calculate bond valuations using financial models and matrices. Fixed income securities are typically classified as Level 2 holdings because their valuation inputs are based on observable market data. Observable inputs used for valuing fixed income securities are benchmark yields, reported trades, broker/dealer quotes, issuer spreads, two-sided markets, benchmark securities, bids, offers, reference data and economic events. Other securities with model-derived valuation inputs that are observable are also classified as Level 2 investments. Investments with unobservable valuation inputs are classified as Level 3 investments. Benefit plan assets included in Level 3 are real estate and private equity investments that are valued using methods requiring judgment including appraisals.

Items classified as Level 2 are primarily investments in individual fixed income securities. These fixed income securities are valued using models with input data as follows:

	Type of Fixed Income Security		
Type of Input	**United States Government**	**Corporate Debt**	**State and Local Government**
Benchmark Yields	X	X	X
Broker Quotes	X	X	X
Discount Margins	X	X	
Treasury Market Update	X		
Base Spread	X	X	X
Corporate Actions		X	
Ratings Agency Updates		X	X
Prepayment Schedule and History			X
Yield Adjustments	X		

Revenues and Expenses

AEPSC provides certain managerial and professional services to both affiliated and nonaffiliated companies. The costs of the services are billed on a direct-charge basis, whenever possible. Costs incurred to perform services that benefit more than one company are allocated to the benefiting companies using one of 80 FERC accepted allocation factors. The allocation factors used to bill for services performed by AEPSC are based upon formulae that consider factors such as number of customers, number of employees, number of transmission pole miles, number of invoices and other factors. The data upon which these formulae are based is updated monthly, quarterly, semi-annually or annually, depending on the particular factor and its volatility. The billings for services are made at cost and include no compensation for a return on investment.

Income Taxes and Investment Tax Credits

AEPSC 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), deferred income taxes are recorded and related regulatory assets and liabilities are established to match the regulated revenues and tax expense.

Investment tax credits have been accounted for under the flow-through method unless they have been deferred in accordance with regulatory treatment. Investment tax credits that have been deferred are amortized over the life of the investment.

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

Investments Held in Trust for Future Liabilities

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

Benefit Plans

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

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

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

The target asset allocation and allocation ranges are as follows:

Pension Plan Assets	Minimum	Target	Maximum
Domestic Equity	30.0 %	35.0 %	40.0 %
International and Global Equity	10.0 %	15.0 %	20.0 %
Fixed Income	35.0 %	39.0 %	45.0 %
Real Estate	4.0 %	5.0 %	6.0 %
Other Investments	1.0 %	5.0 %	7.0 %
Cash	0.5 %	1.0 %	3.0 %

OPEB Plans Assets	Minimum	Target	Maximum
Equity	61.0 %	66.0 %	71.0 %
Fixed Income	29.0 %	32.0 %	37.0 %
Cash	1.0 %	2.0 %	4.0 %

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

For equity investments, the limits are as follows:

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

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

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities
- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

For obligations of non-government issuers the following limitations apply:

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

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

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

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

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

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

Comprehensive Income (Loss)

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

Stock-Based Compensation Plans

At December 31, 2010, AEPSC had stock options, performance units, restricted shares and restricted stock units outstanding under AEP's Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP). This plan was last approved by AEP shareholders in April 2010.

AEPSC maintains a variety of tax qualified and nonqualified deferred compensation plans for employees that include, among other options, an investment in or an investment return equivalent to that of AEP common stock. This includes career share accounts maintained under the American Electric Power System Stock Ownership Requirement Plan, which facilitates executives in meeting minimum stock ownership requirements assigned to them by the Human Resources Committee of AEP's Board of Directors. Career shares are derived from vested performance units granted to employees under the LTIP. Career shares are equal in value to shares of AEP common stock and do not become payable to executives until after their service ends. Dividends paid on career shares are reinvested as additional career shares.

In January 2006, AEPSC adopted accounting guidance for "Compensation - Stock Compensation" which requires the measurement and recognition of compensation expense for all share-based payment awards made to employees, including stock options, based on estimated fair values.

AEPSC recognizes compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on AEPSC's Statements of Operations for the years ended December 31, 2010 and 2009 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2010 and 2009, compensation expense is included in Net Income for the performance units, career shares, restricted shares and restricted stock units. See Note 8 for additional discussion

Mountaineer Carbon Capture and Storage Project

In 2010, AEPSC received a federal stimulus grant for a commercial scale Carbon Capture and Sequestration facility at APCo's Mountaineer Plant. AEPSC submitted Request for Advance or Reimbursement applications to the Department of Energy (DOE) for reimbursement of allowable program costs. The applications designated APCo as the payee and cash receipts from the DOE were paid directly to APCo.

Adjustments to Benefit Plans Footnote

In Note 4 – Benefit Plans, the disclosure was expanded to reflect disclosure requirements based upon AEPSC's participation in the AEP System. These omissions were not material to the financial statements and had no impact on AEPSC's previously reported results of operation, changes in shareholder's equity, financial position or cash flows.

Subsequent Events

Management reviewed subsequent events through April 6, 2011, the date that AEPSC's 2010 Annual Report was available to be issued.

2. EFFECTS OF REGULATION

Recognized regulatory assets and liabilities are comprised of the following items:

	December 31, 2010	December 31, 2009	Remaining Recovery Period
	(in thousands)		
Noncurrent Regulatory Assets			
Regulatory assets being recovered:			
Regulatory Assets Currently Not Earning a Return			
Amounts Due from Affiliates for Pension and OPEB Funded Status	$ 684,303	$ 643,185	13 years
Total Regulatory Assets	$ 684,303	$ 643,185	

Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Not Paying a Return			
Deferred Amounts Due to Affiliates for Income Tax Benefits	$ 3,267	$ 8,301	29 years
Deferred Investment Tax Credits	394	444	8 years
Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,661	$ 8,745	

3. COMMITMENTS, GUARANTEES AND CONTINGENCIES

AEPSC is subject to certain claims and legal actions arising in its ordinary course of business. 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.

COMMITMENTS

Construction and Commitments

AEPSC has construction commitments to support its operations. In managing the overall construction program and in the normal course of business, AEPSC contractually commits to third-party construction vendors for certain material purchases and other construction services. AEPSC also 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. AEPSC has no contractual commitments at December 31, 2010.

GUARANTEES

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

Letters of Credit

AEPSC enters into standby letters of credit (LOCs) with third parties. These LOCs cover items such as insurance programs, security deposits and debt service reserves. These LOCs were issued in the ordinary course of business. At December 31, 2010, the maximum future payments of the LOCs for AEPSC were $70 million with maturities ranging from January 2011 to October 2011.

CONTINGENCIES

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 trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases 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 CO_2 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. In December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. Briefing is underway and the case will be heard in April 2011. Management believes the actions are without merit and intends to continue to defend against the claims.

In October 2009, the Fifth Circuit Court of Appeals reversed a decision by the Federal District Court for the District of Mississippi dismissing state common law nuisance claims in a putative class action by Mississippi residents asserting that CO_2 emissions exacerbated the effects of Hurricane Katrina. The Fifth Circuit held that there was no exclusive commitment of the common law issues raised in plaintiffs' complaint to a coordinate branch of government and that no initial policy determination was required to adjudicate these claims. The court granted petitions for rehearing. An additional recusal left the Fifth Circuit without a quorum to reconsider the decision and the appeal was dismissed, leaving the district court's decision in place. Plaintiffs filed a petition with the U.S. Supreme Court asking the court to remand the case to the Fifth Circuit and reinstate the panel decision. The petition was denied in January 2011.

Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. Management believes the action is without merit and intends to defend against the claims. Management is unable to determine a range of potential losses that are reasonably possible of occurring.

Insurance and Potential Losses

AEPSC maintains insurance coverage normal and customary for electric utilities, subject to various deductibles. Insurance coverage includes all risks of physical loss or damage to AEPSC assets, subject to insurance policy conditions and exclusions. Covered property generally includes AEPSC facilities and inventories. The insurance programs also generally provide coverage against loss arising from certain claims made by third parties. Coverage is generally provided by a combination of the protected cell of EIS and/or various industry mutual and/or commercial insurance carriers.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities. Future losses or liabilities, which are not completely insured, would be recovered from affiliated companies.

4. BENEFIT PLANS

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

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

AEPSC recognizes its funded status associated with defined benefit pension and OPEB plans in its balance sheets. Disclosures about the plans are required by the "Compensation – Retirement Benefits" accounting guidance. AEPSC recognizes an asset for a plan's overfunded status or a liability for a plan's underfunded status. AEPSC records a regulatory asset instead of other comprehensive income for qualifying benefit costs of regulated operations that will be billed to affiliated companies.

Actuarial Assumptions for Benefit Obligations

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

	Pension Plans		Other Postretirement Benefit Plans	
Assumptions	**2010**	**2009**	**2010**	**2009**
Discount Rate	5.05%	5.60%	5.25%	5.85%
Rate of Compensation Increase	4.95% (a)	4.60% (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

A duration-based method is used to determine the discount rate for the plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed 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 2010, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.95%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans		Other Postretirement Benefit Plans	
	2010	**2009**	**2010**	**2009**
Discount Rate	5.60%	6.00%	5.85%	6.10%
Expected Return on Plan Assets	8.00%	8.00%	8.00%	7.75%
Rate of Compensation Increase	4.60%	5.90%	N/A	N/A

N/A Not Applicable

The expected return on plan assets for 2010 was determined by evaluating historical returns, the current investment climate (yield on fixed income securities and other recent investment market indicators), rate of inflation and current prospects for economic growth.

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

Health Care Trend Rates	2010	2009
Initial	8.00%	6.50%
Ultimate	5.00%	5.00%
Year Ultimate Reached	2016	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 thousands)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 5,161	$ (4,161)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	52,473	(43,048)

Significant Concentrations of Risk within Plan Assets

In addition to establishing the target asset allocation of plan assets, the investment policy also places restrictions on securities to limit significant concentrations within plan assets. The investment policy establishes guidelines that govern maximum market exposure, security restrictions, prohibited asset classes, prohibited types of transactions, minimum credit quality, average portfolio credit quality, portfolio duration and concentration limits. The guidelines were established to mitigate the risk of loss due to significant concentrations in any investment. The plans are monitored to control security diversification and ensure compliance with the investment policy. At December 31, 2010, the assets were invested in compliance with all investment limits. See "Investments Held in Trust for Future Liabilities" section of Note 1 for limit details.

Benefit Plan Obligations, Plan Assets and Funded Status as of December 31, 2010 and 2009

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

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
Change in Benefit Obligation	(in thousands)			
Benefit Obligation at January 1	$ 1,344,344	$ 1,211,010	$ 410,155	$ 385,237
Service Cost	37,600	35,176	13,300	12,226
Interest Cost	74,926	72,901	23,914	23,175
Actuarial Loss	118,367	97,636	27,761	3,812
Plan Amendment Prior Service Credit	-	-	(10,604)	-
Benefit Payments	(118,207)	(72,379)	(25,928)	(19,930)
Participant Contributions	-	-	5,891	4,587
Medicare Subsidy	-	-	1,109	1,048
Benefit Obligation at December 31	$ 1,457,030	$ 1,344,344	$ 445,598	$ 410,155
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 876,523	$ 810,488	$ 286,903	$ 220,994
Actual Gain on Plan Assets	133,521	130,774	29,830	51,672
Company Contributions	271,256	7,640	23,084	29,580
Participant Contributions	-	-	5,891	4,587
Benefit Payments	(118,207)	(72,379)	(25,928)	(19,930)
Fair Value of Plan Assets at December 31	$ 1,163,093	$ 876,523	$ 319,780	$ 286,903
Underfunded Status at December 31	$ (293,937)	$ (467,821)	$ (125,818)	$ (123,252)

Amounts Recognized on the Balance Sheets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
	(in thousands)			
Other Current Liabilities – Accrued Short-term Benefit Liability	$ (7,080)	$ (8,932)	$ -	$ -
Employee Pension Obligations – Accrued Long-term Benefit Liability	(286,857)	(458,889)	-	-
Other Postemployment Benefit Obligations – Accrued Long-term Benefit Liability	-	-	(125,818)	(123,252)
Underfunded Status	$ (293,937)	$ (467,821)	$ (125,818)	$ (123,252)

Amounts Included in Regulatory Assets as of December 31, 2010 and 2009

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
Components	(in thousands)			
Net Actuarial Loss	$ 553,525	$ 513,815	$ 134,046	$ 119,276
Prior Service Cost (Credit)	5,023	6,181	(8,291)	1,871
Transition Obligation	-	-	-	2,042
Recorded as				
Regulatory Assets	$ 558,548	$ 519,996	$ 125,755	$ 123,189

Components of the change in amounts included in Regulatory Assets during the years ended December 31, 2010 and 2009 are as follows:

	Pensions Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2010	2009	2010	2009
Components	(in thousands)			
Actuarial Loss (Gain) During the Year	$ 66,052	$ 49,934	$ 20,622	$ (30,650)
Prior Service Credit	-	-	(10,604)	-
Amortization of Actuarial Loss	(26,343)	(17,642)	(5,851)	(8,735)
Amortization of Prior Service Cost	(1,157)	(1,335)	(266)	(266)
Amortization of Transition Obligation	-	-	(1,335)	(1,335)
Change for the Year	$ 38,552	$ 30,957	$ 2,566	$ (40,986)

5. INCOME TAXES

The details of income taxes are as follows:

	Years Ended December 31, 2010	2009
	(in thousands)	
Income Tax Expense (Credit):		
Current	$ (46,610)	$ (4,169)
Deferred	58,603	(8,277)
Deferred Investment Tax Credits	(51)	(51)
Total Income Tax (Credit)	$ 11,942	$ (12,497)

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 total amount of income taxes as reported:

	Years Ended December 31, 2010	2009
	(in thousands)	
Net Income	$ -	$ -
Income Taxes	11,942	(12,497)
Pre-Tax Income (Loss)	$ 11,942	$ (12,497)
Income Tax on Pretax Income (Loss) at Statutory Rate (35%)	$ 4,180	$ (4,374)
Increase (Decrease) in Income Tax Resulting from the Following Items:		
Trust Owned Life Insurance	(3,893)	(5,006)
State and Local Income Taxes	(1,023)	(424)
Medicare Subsidy	11,961	(2,760)
Other	717	67
Total Income Tax Credit	$ 11,942	$ (12,497)
Effective Income Tax Rate	N.M.	N.M.

N.M. Not Meaningful

The following table shows the elements of the net deferred tax asset and the significant temporary differences:

	December 31, 2010	December 31, 2009
	(in thousands)	
Deferred Tax Assets	$ 174,438	$ 182,341
Deferred Tax Liabilities	(170,520)	(114,747)
Net Deferred Tax Assets	$ 3,918	$ 67,594
Property Related Temporary Differences	$ (11,243)	$ (14,525)
Deferred and Accrued Compensation	63,990	50,668
Accrued Pension	71,971	129,022
Accrued Vacation Pay	12,913	14,860
Postretirement Benefits	114,693	104,810
Deferred State Income Taxes	(265)	4,475
Amounts Due to Affiliates for Future Income Taxes	1,235	1,339
Regulatory Assets	(239,506)	(225,115)
All Other, Net	(9,870)	2,060
Net Deferred Tax Assets	$ 3,918	$ 67,594

AEPSC 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.

AEPSC and other AEP subsidiaries are no longer subject to U.S. federal examination for years before 2001. AEPSC 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, AEPSC 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.

AEPSC, along with other AEP subsidiaries, files income tax returns in various state and local jurisdictions. These taxing authorities routinely examine the tax returns and AEPSC and other AEP subsidiaries are currently under examination in several state and local jurisdictions. Management believes that previously filed tax returns have positions that may be challenged by these tax authorities. However, management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges, and the ultimate resolution of these audits will not materially impact results of operations. With few exceptions, AEPSC is no longer subject to state or local income tax examinations by tax authorities for years before 2000.

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

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

	Years Ended December 31, 2010	2009
	(in thousands)	
Interest Expense	$ -	$ 761
Interest Income	595	-
Reversal of Prior Period Interest Expense	47	-

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

	December 31, 2010	2009
	(in thousands)	
Accrual for Receipt of Interest	$ -	$ -
Accrual for Payment of Interest and Penalties	1,298	1,939

AEPSC's reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

	2010	2009
	(in thousands)	
Balance at January 1,	$ 5,400	$ 3,210
Increase - Tax Positions Taken During a Prior Period	13	2,561
Decrease - Tax Positions Taken During a Prior Period	(40)	(371)
Increase - Tax Positions Taken During the Current Year	-	-
Decrease - Tax Positions Taken During the Current Year	-	-
Decrease - Settlements with Taxing Authorities	(34)	-
Decrease - Lapse of the Applicable Statute of Limitations	-	-
Balance at December 31,	$ 5,339	$ 5,400

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $3.1 million for both 2010 and 2009. Management believes there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date

Federal Tax Legislation

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not materially impact AEPSC's results of operations, cash flows or financial condition.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, an approximate $13 million reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded by AEPSC in March 2010. This reduction did not materially affect AEPSC's results of operations, cash flows or financial condition.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization, and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provision will not materially impact AEPSC's results of operations, cash flows or financial condition.

State Tax Legislation

In March 2008, legislation was signed 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 AEPSC's results of operations, cash flows or financial condition.

6. LEASES

Leases of structures, improvements, office furniture and miscellaneous equipment are for periods of up to 30 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 and Maintenance expense. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2010	2009
	(in thousands)	
Net Lease Expense on Operating Leases	$ 9,908	$ 9,221
Amortization of Capital Leases	18,628	24,626
Interest on Capital Leases	2,245	1,819
Total Lease Rental Costs	$ 30,781	$ 35,666

The following table shows the property, plant and equipment under capital leases and related obligations recorded on AEPSC's Balance Sheets:

	December 31, 2010	2009
	(in thousands)	
Property and Equipment Under Capital Leases		
Structures and Improvements	$ 11,750	$ 11,750
Office Furniture and Miscellaneous Equipment	58,935	81,334
Total Property and Equipment Under Capital Leases	70,685	93,084
Accumulated Amortization	26,459	47,747
Net Property and Equipment Under Capital Leases	$ 44,226	$ 45,337
Obligations Under Capital Leases		
Noncurrent Liability	$ 29,553	$ 28,573
Liability Due Within One Year	14,673	16,764
Total Obligations Under Capital Leases	$ 44,226	$ 45,337

Future minimum lease payments consisted of the following at December 31, 2010:

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in thousands)	
2011	$ 16,685	$ 7,877
2012	13,724	7,189
2013	8,956	6,664
2014	5,650	6,386
2015	2,462	6,187
Later Years	2,598	9,614
Total Future Minimum Lease Payments	50,075	$ 43,917
Less Estimated Interest Element	5,849	
Estimated Present Value of Future Minimum Lease Payments	$ 44,226	

Master Lease Agreements

AEPSC leases certain equipment under master lease agreements. In December 2010, management signed a new master lease agreement with GE Capital Commercial Inc. (GE) to replace existing operating and capital leases with GE. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Certain assets were not included in the refinancing, but the assets will be purchased or refinanced in 2011. In addition, certain operating leases that were previously under lease with GE are now recorded as capital leases after the refinancing. The amounts refinanced for AEPSC are as follows:

Leases Refinanced with GE	AEPSC
	(in thousands)
Operating Lease to Operating Lease	$ 3,202
Capital Lease to Capital Lease	6,284
Operating Lease to Capital Lease	523

These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 84% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, AEPSC is committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 84% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, AEPSC is committed to pay the difference between the actual fair value and the residual value guarantee. At December 31, 2010, the maximum potential loss for these lease agreements was approximately $646 thousand ($420 thousand net of tax) assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Aircraft Lease

In December 2010, AEPSC bought out the lease on aircraft acquired in 2008 and incurred a loss of $10.9 million on the buyout of the lease. The loss was recorded in Operation and Maintenance expense on the Statements of Operations for the year ended December 31, 2010 and was subsequently billed to AEP Parent. Also in December 2010, AEPSC purchased two new aircraft for $24 million. AEPSC applied the trade-in value of the old aircraft of $10.2 million to offset the purchase price of the new aircraft. The purchase is reflected in Acquisitions of Assets and the loss incurred on the buy out of the lease is reflected in Loss on Sale of Assets within Investing Activities and Operating Activities, respectively, on AEPSC's 2010 Statements of Cash Flows. In March 2011, AEPSC executed a sale-leaseback financing transaction whereby AEPSC sold the new aircraft and signed a 10-year lease.

7. 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 AEP's utility subsidiaries. The AEP System Utility Money Pool operates in accordance with the terms and conditions approved in a regulatory order. AEPSC's amounts of outstanding borrowings from the Utility Money Pool as of December 31, 2010 and 2009 are included in Advances from Affiliates on AEPSC's Balance Sheets. AEPSC's activity in the Utility Money Pool for the years ended December 31, 2010 and 2009 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,
			(in thousands)		
2010	$ 327,935	$ 3,111	$ 126,710	$ 3,111	$ 320,181
2009	201,169	66,012	103,327	20,943	98,617

Maximum, minimum and average interest rates for funds either borrowed from or loaned to the Utility Money Pool for the years ended December 31, 2010 and 2009 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
2010	0.55%	0.09%	0.14%	0.14%	0.29%	0.14%
2009	2.28%	0.15%	1.82%	1.73%	0.76%	1.76%

Interest expense and interest income related to the Utility Money Pool are included in Interest Expense and Interest Income, respectively, in AEPSC's Statements of Operations. For amounts borrowed from and advanced to the Utility Money Pool, AEPSC incurred the following amounts of interest expense and earned the following amounts of interest income, respectively, for the years ended December 31, 2010 and 2009:

	Years Ended December 31, 2010	2009
	(in thousands)	
Interest Expense	$ 365	$ 764
Interest Income	-	15

8. STOCK-BASED COMPENSATION

AEPSC participates in AEP's Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) which authorizes the use of shares of AEP common stock for various types of stock-based compensation awards, including stock options, performance units, restricted shares and restricted stock units. AEPSC employees comprise the majority of participants and they hold the majority of shares and units outstanding under AEP's share-based compensation plans. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of AEP's Board of Directors (HR Committee).

Stock Options

AEP did not grant stock options in 2010 or 2009 but does have outstanding stock options from grants in earlier periods that vested or were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. Stock options are AEP equity instruments and are recorded on AEP's Consolidated Balance Sheets. AEPSC records its portion of compensation cost for stock options over the vesting period based on the fair value on the grant date. Compensation costs were fully expensed in 2007. No compensation costs were recorded in 2010 or 2009. The LTIP does not specify a maximum contractual term for stock options.

Performance Units

Performance units are equal in value to the market value of shares of AEP common stock. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee and can range from 0% to 200%. For the three-year performance and vesting period ending in 2009 and earlier performance periods, performance units are paid in cash or stock at the employee's election unless they are needed to satisfy a participant's stock ownership requirement. Starting with the three-year performance and vesting period ending in 2010 or later, performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that have a value equivalent to shares of AEP common stock and are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and AEP Career Shares accrue as additional units. AEPSC recorded compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Incentive Compensation Plans on AEPSC's Balance Sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares to AEPSC employees for the years ended December 31, 2010 and 2009 as follows:

AEPSC Performance Units	Years Ended December 31, 2010	2009
Awarded Units (in thousands)	649	1,012
Weighted Average Unit Fair Value at Grant Date	$ 35.44	$ 34.33
Vesting Period (years)	3	3

AEPSC Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2010	2009
Awarded Units (in thousands)	188	201
Weighted Average Grant Date Fair Value	$ 34.70	$ 28.82
Vesting Period (years)	(a)	(a)

(a) The vesting period for the reinvested dividends on performance units is equal to the remaining life of the related performance units. Dividends on AEP Career Shares vest immediately upon grant.

Performance scores and final awards are determined and certified by the HR Committee in accordance with the pre-established performance measures within approximately a month after the end of the performance period. The HR Committee has discretion to reduce or eliminate the value of final awards, but may not increase them. The performance scores for all open performance periods are dependent on two equally-weighted performance measures: (a) three-year total shareholder return measured relative to the utility industry segment of the Standard & Poor's 500 Index and (b) three-year cumulative earnings per share measured relative to an AEP Board of Directors approved target. The value of each performance unit earned equals the average closing price of AEP common stock for the last 20 business days of the performance period.

Certified performance scores and units earned by AEPSC employees for the years ended December 31, 2010 and 2009 were as follows:

	Years Ended December 31, 2010	2009
Certified Performance Score	55.8%	73.5%
Performance Units Earned	433,148	528,929
Performance Units Manditorily Deferred as AEP Career Shares	29,855	19,513
Performance Units Voluntarily Deferred into the Incentive Compensation Deferral Program	5,318	21,734
Performance Units to be Paid in Cash	397,975	487,682

Cash payouts to AEPSC employees for the years ended December 31, 2010 and 2009 were as follows:

	Years Ended December 31, 2010	2009
	(in thousands)	
Cash Payouts for Performance Units	$ 16,934	$ 27,532
Cash Payouts for AEP Career Share Distributions	3,366	2,168

Restricted Shares and Restricted Stock Units

The independent members of the AEP Board of Directors granted 300,000 restricted shares to the then Chairman, President and CEO on January 2, 2004 upon the commencement of his AEP employment. Of these restricted shares, 50,000 vested on January 1, 2005, 50,000 vested on January 1, 2006, 66,666 vested on November 30, 2009 and 66,667 vested on November 30, 2010. The remaining 66,667 restricted shares will vest on November 30, 2011, subject to his continued AEP employment through that date. Restricted shares are AEP equity instruments and are recorded on AEP's Consolidated Balance Sheets. AEPSC's portion of compensation cost related to restricted shares is measured at fair value on the grant date and recorded over the vesting period on AEPSC's Statements of Operations. Fair value is determined by multiplying the number of shares granted by the grant date market closing price, which was $30.76. The maximum term for these restricted shares is eight years and dividends on these restricted shares are paid in cash. AEP has not granted other restricted shares.

The HR Committee also grants restricted stock units (RSUs), which generally vest, subject to the participant's continued employment, over at least three years in approximately equal annual increments on the anniversaries of the grant date. For awards granted prior to 2009, additional RSUs granted as dividends vest on the last date associated with that RSU grant. For awards granted in 2009 and later, additional RSUs granted as dividends vest on the same date as the underlying RSUs on which the dividends were awarded. RSUs are AEP equity instruments and are recorded on AEP's Consolidated Balance Sheets. AEPSC's portion of compensation cost related to RSUs is measured at fair value on the grant date and recorded over the vesting period on AEPSC's Statements of Operations. Fair value is determined by multiplying the number of units granted by the grant date market closing price. The maximum contractual term of outstanding RSUs is five years from the grant date.

In 2010, the HR Committee granted a total of 165,520 of RSUs to four CEO succession candidates to better ensure the retention of these candidates. These grants vest, subject to the candidates' continuous employment, in three approximately equal installments on August 3, 2013, August 3, 2014 and August 3, 2015.

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2010 and 2009 as follows:

AEP Restricted Stock Units	Years Ended December 31, 2010	2009
Awarded Units (in thousands)	873	130
Weighted Average Grant Date Fair Value	$ 35.24	$ 29.29

AEP's total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2010 and 2009 were as follows:

AEP Restricted Shares and Restricted Stock Units	Years Ended December 31, 2010	2009
	(in thousands)	
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 6,044	$ 6,573
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	5,993	5,445

(a) Intrinsic value is calculated as market price at exercise date.

A summary of the status of AEP's nonvested restricted shares and RSUs as of December 31, 2010 and changes during the year ended December 31, 2010 are as follows:

Nonvested Restricted Shares and Restricted Stock Units	Shares/Units	Weighted Average Grant Date Fair Value
	(in thousands)	
Nonvested at January 1, 2010	366	$ 34.12
Granted	873	35.24
Vested	(173)	35.00
Forfeited	(40)	35.01
Nonvested at December 31, 2010	1,026	34.88

AEP's total aggregate intrinsic value of nonvested restricted shares and RSUs as of December 31, 2010 was $37 million and the weighted average remaining contractual life was 3.09 years.

Share-based Compensation Plans

AEPSC's compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2010 and 2009 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2010	2009
	(in thousands)	
Compensation Cost for Share-based Payment Arrangements (a)	$ 21,632	$ 24,425
Actual Tax Benefit Realized	7,571	8,549
Total Compensation Cost Capitalized	3,924	4,958

(a) Compensation cost for share-based payment arrangements is included in Operation and Maintenance on AEPSC's Statements of Operations.

During the years ended December 31, 2010 and 2009, there were no significant modifications affecting any of AEP's share-based payment arrangements.

As of December 31, 2010, AEP had $81 million of total unrecognized compensation cost related to unvested share-based compensation arrangements granted under the LTIP. Unrecognized compensation cost related to the performance units and AEP Career Shares will change as the fair value is adjusted each period and forfeitures for all award types are realized. AEP's unrecognized compensation cost will be recognized over a weighted-average period of 1.84 years.

AEP's practice is to use authorized but unissued shares to fulfill share commitments for stock option exercises and RSU vesting. Although AEP does not currently anticipate any changes to this practice, AEP could use treasury shares, shares acquired in the open market specifically for distribution under the LTIP or any combination thereof for this purpose. The number of new shares issued to fulfill vesting RSUs is generally reduced to offset AEP's tax withholding obligation.

9. RELATED PARTY TRANSACTIONS

CSPCo Transfer of Property

In 2009, AEP transferred a parking garage to AEPSC through a capital contribution. The transfer was recorded at AEP's net book value of $8 million.

10. COST REDUCTION INITIATIVES

In April 2010, management began initiatives to decrease both labor and non-labor expenses with a goal of achieving significant reductions in operation and maintenance expenses. A total of 2,461 positions were eliminated across the AEP System as a result of process improvements, streamlined organizational designs and other efficiencies. Most of the affected employees terminated employment May 31, 2010. The severance program provides two weeks of base pay for every year of service along with other severance benefits.

AEPSC recorded a charge to expense in 2010 primarily related to the headcount reduction initiatives. All expenses incurred have been allocated to AEP affiliates. Management does not expect additional costs to be incurred related to this initiative.

Incurred	Settled	Adjustments	Remaining Balance at December 31, 2010
		(in millions)	
$ 106	$ 99	$ 1	$ 8

These costs relate primarily to severance benefits. They are included primarily in Operation and Maintenance expense on the Statement of Operations and in Other Current Liabilities on the Balance Sheets.

Instruction 2

See Footnote 3 "Commitments, Guarantees and Contingencies", for a discussion of contingent assets or liabilities existing at the end of the year.

Instruction 3

No significant increases in services rendered or expenses were incurred during the year.

Instruction 4

Not applicable

Instruction 5

Not applicable

Instruction 6

Since this FERC Form 60 is distributed to the appropriate members of AEP's management each year, they are receiving notification concerning the amount of compensation for use of capital billed during the year. In addition, monthly service billings are provided that detail all components of billings to affiliate companies.

The basis for billing of interest to the associate companies is allocation factor number 37-AEPSC Past 3 Months Total Bill Dollars. The amount of compensation for use of capital billed during the year to each associate company is provided on page 307, "Analysis of Billing - Associated Companies".

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Schedule XV- Comparative Income Statement

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
1		**SERVICE COMPANY OPERATING REVENUES**		
2	400	Service Company Operating Revenues	1,231,052,049	1,080,069,002
3		**SERVICE COMPANY OPERATING EXPENSES**		
4	401	Operation Expenses	790,378,551	659,041,624
5	402	Maintenance Expenses	105,689,239	87,635,241
6	403	Depreciation Expenses	4,619,867	2,834,355
7	403.1	Depreciation Expense for Asset Retirement Costs		
8	404	Amortization of Limited-Term Property	618,120	325,927
9	405	Amortization of Other Property		
10	407.3	Regulatory Debits		
11	407.4	Regulatory Credits		
12	408.1	Taxes Other Than Income Taxes, Operating Income	44,879,823	(973,375)
13	409.1	Income Taxes, Operating Income	(46,610,593)	(4,169,275)
14	410.1	Provision for Deferred Income Taxes, Operating Income	147,805,248	258,157,238
15	411.1	Provision for Deferred Income Taxes – Credit , Operating Income	(89,201,750)	(266,434,042)
16	411.4	Investment Tax Credit, Service Company Property	(50,808)	(50,808)
17	411.6	Gains from Disposition of Service Company Plant		
18	411.7	Losses from Disposition of Service Company Plant		
19	411.10	Accretion Expense		
20	412	Costs and Expenses of Construction or Other Services	252,328,484	340,041,351
21	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work		
22		TOTAL SERVICE COMPANY OPERATING EXPENSES (Total of Lines 4-21)	1,210,456,181	1,076,408,206
23		NET SERVICE COMPANY OPERATING INCOME (Total of Lines 2 less 22)	20,595,868	3,660,796
24		**OTHER INCOME**		
25	418.1	Equity in Earnings of Subsidiary Companies		
26	419	Interest and Dividend Income	122	18,883
27	419.1	Allowance for Other Funds Used During Construction		(90)
28	421	Miscellaneous Income or Loss	905,342	467,558
29	421.1	Gain on Disposition of Property		
30		**TOTAL OTHER INCOME (Total of Lines 25-29)**	905,464	486,351
31		**OTHER INCOME DEDUCTIONS**		
32	421.2	Loss on Disposition of Property	10,869,176	
33	425	Miscellaneous Amortization		
34	426.1	Donations	1,652,373	1,189,788
35	426.2	Life Insurance		
36	426.3	Penalties	31,094	87,744
37	426.4	Expenditures for Certain Civic, Political and Related Activities	5,286,633	2,929,281
38	426.5	Other Deductions	3,406,352	(1,827,918)
39		**TOTAL OTHER INCOME DEDUCTIONS (Total of Lines 32-38)**	21,245,628	2,378,895

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Schedule XV- Comparative Income Statement (continued)

Line No.	Account Number (a)	Title of Account (b)	Current Year (c)	Prior Year (d)
40		**TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS**		
41	408.2	Taxes Other Than Income Taxes, Other Income and Deductions	1,466	1,907
42	409.2	Income Taxes, Other Income and Deductions		
43	410.2	Provision for Deferred Income Taxes, Other Income and Deductions		
44	411.2	Provision for Deferred Income Taxes – Credit, Other Income and Deductions		
45	411.5	Investment Tax Credit, Other Income Deductions		
46		**TOTAL TAXES APPLICABLE TO OTHER INCOME AND DEDUCTIONS (Total of Lines 41-45)**	1,466	1,907
47		**INTEREST CHARGES**		
48	427	Interest on Long-Term Debt		
49	428	Amortization of Debt Discount and Expense		
50	429	(less) Amortization of Premium on Debt- Credit		
51	430	Interest on Debt to Associate Companies	364,670	764,473
52	431	Other Interest Expense	(109,854)	927,623
53	432	(less) Allowance for Borrowed Funds Used During Construction-Credit	578	(74,249)
54		**TOTAL INTEREST CHARGES (Total of Lines 48-53)**	254,238	1,766,345
55		**NET INCOME BEFORE EXTRAORDINARY ITEMS (Total of Lines 23, 30, minus 39, 46, and 54)**		
56		**EXTRAORDINARY ITEMS**		
57	434	Extraordinary Income		
58	435	(less) Extraordinary Deductions		
59		**Net Extraordinary Items (Line 57 less Line 58)**		
60	409.4	(less) Income Taxes, Extraordinary		
61		**Extraordinary Items After Taxes (Line 59 less Line 60)**		
62		**NET INCOME OR LOSS/COST OF SERVICE (Total of Lines 55-61)**		

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FOOTNOTE DATA

Schedule Page: 301 Line No.: 4 Column: d

401 Operation Expense - Per Books	918,040,696
Adjustment for Transfers	(258,999,071)
	659,041,625

Schedule Page: 301 Line No.: 5 Column: d

402 Maintenance Expense - Per Books	123,933,464
Adjustment for Transfers	(36,298,254)
	87,635,210

Schedule Page: 301 Line No.: 6 Column: d

403 Depreciation Expense - Per Books	6,503,571
Adjustment for Transfers	(3 669,216)
	2,834,355

Schedule Page: 301 Line No.: 8 Column: d

404 Amortization of Limited-Term Property -	571,820
Per Books Adjustment for Transfers	(245,893)
	325,927

Schedule Page: 301 Line No.: 12 Column: d

408.1 Taxes Other Than Income Taxes,	36,233,152
Operating Income Expense - Per Books	(37,206,527)
Adjustment for Transfers	(973,375)

Schedule Page: 301 Line No.: 27 Column: d

419.1 Allowance for Other Funds Used During	(205)
Construction - Per Books Adjustment for Transfers	115
	(90)

Schedule Page: 301 Line No.: 28 Column: d

421 Miscellaneous Income or Loss - Per Books	869,630
Adjustment for Transfers	(402,072)
	467,558

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies

1. Total cost of service will equal for associate and nonassociate companies the total amount billed under their separate analysis of billing schedules.

Line No	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
1	403-403.1	Depreciation Expense	2,594,438	2,025,429	4,619,867			
2	404-405	Amortization Expense	398,603	219,517	618,120			
3	407.3-407.4	Regulatory Debits/Credits – Net						
4	408.1-408.2	Taxes Other Than Income Taxes	43,765,319	1,115,970	44,881,289			
5	409.1-409.3	Income Taxes	(46,610,593)		(46,610,593)			
6	410.1-411.2	Provision for Deferred Taxes	147,805,248		147,805,248			
7	411.1-411.2	Provision for Deferred Taxes – Credit	89,201,750		89,201,750			
8	411.6	Gain from Disposition of Service Company Plant						
9	411.7	Losses from Disposition of Service Company Plant						
10	411.4-411.5	Investment Tax Credit Adjustment	50,808		50,808			
11	411.10	Accretion Expense						
12	412	Costs and Expenses of Construction or Other Services	219,030,751	32,684,157	251,714,908	513,304	100,272	613,576
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies						
14	418	Non-operating Rental Income						
15	418.1	Equity in Earnings of Subsidiary Companies						
16	419	Interest and Dividend Income	122		122			
17	419.1	Allowance for Other Funds Used During Construction						
18	421	Miscellaneous Income or Loss	627,696	277,646	905,342			
19	421.1	Gain on Disposition of Property						
20	421.2	Loss on Disposition Of Property	10,869,176		10,869,176			
21	425	Miscellaneous Amortization						
22	426.1	Donations	1,652,373		1,652,373			
23	426.2	Life Insurance						
24	426.3	Penalties	31,094		31,094			
25	426.4	Expenditures for Certain Civic, Political and Related Activities	4,974,575	312,058	5,286,633			
26	426.5	Other Deductions	2,744,204	662,147	3,406,351			
27	427	Interest On Long-Term Debt						
28	428	Amortization of Debt Discount and Expense						
29	429	Amortization of Premium on Debt – Credit						
30	430	Interest on Debt to Associate Companies	364,670		364,670			
31	431	Other Interest Expense	(109,854)		(109,854)			
32	432	Allowance for Borrowed Funds Used During Construction	(578)		(578)			
33	500-509	Total Steam Power Generation Operation Expenses	64,544,005	11,175,210	75,719,215	1,093,562	71,276	1,164,838
34	510-515	Total Steam Power Generation Maintenance Expenses	23,586,003	4,335,732	27,921,735	64,646	5,151	69,797

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Line No	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
35	517-525	Total Nuclear Power Generation Operation Expenses	159.470	571.888	731,358	1.402		1,402
36	528-532	Total Nuclear Power Generation Maintenance Expenses	1,109,843	422,160	1.532,003			
37	535-540 1	Total Hydraulic Power Generation Operation Expenses	1,287,766	521,206	1,808,972			
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	503,596	236,390	739,986			
39	546-550 1	Total Other Power Generation Operation Expenses	293,003	97,822	390,825			
40	551-554 1	Total Other Power Generation Maintenance Expenses	32,649	5,019	37,668			
41	555-557	Total Other Power Supply Operation Expenses	22,707,983	15,169,927	37,877,910	929	304	1,233
42	560	Operation Supervision and Engineering	10,315,161	3,475,711	13,790,872	55,300	7,102	62,402
43	561 1	Load Dispatch-Reliability	82,526	160.174	242,700			
44	561.2	Load Dispatch-Monitor and Operate Transmission System	4,025,911	5,285,243	9.311,154			
45	561.3	Load Dispatch-Transmission Service and Scheduling	(52,675)	101,715	49.040			
46	561 4	Scheduling, System Control and Dispatch Services	45,888		45,888			
47	561 5	Reliability Planning and Standards Development	635,673	686.866	1,322,539			
48	561.6	Transmission Service Studies						
49	561 7	Generation Interconnection Studies						
50	561.8	Reliability Planning and Standards Development Services						
51	562	Station Expenses (Major Only)	76,376	15,512	91.888			
52	563	Overhead Line Expenses (Major Only)	47,118	13,737	60.855			
53	564	Underground Line Expenses (Major Only)						
54	565	Transmission of Electricity by Others (Major Only)						
55	566	Miscellaneous Transmission Expenses (Major Only)	23,435,077	1,402.100	24.837,177	11,919	27	11,946
56	567	Rents	600		600			
57	567.1	Operation Supplies and Expenses (Nonmajor Only)						
58		Total Transmission Operation Expenses	38,611,655	11,141,058	49,752,713	67,219	7,129	74,348
59	568	Maintenance Supervision and Engineering (Major Only)	616.346	156,634	772,980			
60	569	Maintenance of Structures (Major Only)	1.711	136	1,847			
61	569.1	Maintenance of Computer Hardware	30,957	67,850	98,807			
62	569.2	Maintenance of Computer Software	1,698,527	1,397,150	3,095,677			
63	569 3	Maintenance of Communication Equipment	832	45,735	46,567			
64	569 4	Maintenance of Miscellaneous Regional Transmission Plant						
65	570	Maintenance of Station Equipment (Major Only)	1,281,256	329,741	1,610,997			
66	571	Maintenance of Overhead Lines (Major Only)	417,555	921,917	1,339,472			
67	572	Maintenance of Underground Lines (Major Only)	1,437	412	1,849			
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	5.451	227	5,678			

Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
69	574	Maintenance of Transmission Plant (Nonmajor Only)						
70		Total Transmission Maintenance Expenses	4,054,072	2,919,802	6,973,874			
71	575 1-575 8	Total Regional Market Operation Expenses						
72	576 1-576 5	Total Regional Market Maintenance Expenses						
73	580-589	Total Distribution Operation Expenses	29,715,066	13,564,405	43,279,471			
74	590-598	Total Distribution Maintenance Expenses	1,351,410	711,679	2,063,089			
75		Total Electric Operation and Maintenance Expenses	485,585,571	97,613,930	583,199,501	1,741,062	184,132	1,925,194
76	700-798	Production Expenses (Provide selected accounts in a footnote)						
77	800-813	Total Other Gas Supply Operation Expenses						
78	814-826	Total Underground Storage Operation Expenses						
79	830-837	Total Underground Storage Maintenance Expenses						
80	840-842 3	Total Other Storage Operation Expenses						
81	843 1-843 9	Total Other Storage Maintenance Expenses						
82	844 1-846 2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses						
83	847 1-847 8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses						
84	850	Operation Supervision and Engineering						
85	851	System Control and Load Dispatching						
86	852	Communication System Expenses						
87	853	Compressor Station Labor and Expenses						
88	854	Gas for Compressor Station Fuel						
89	855	Other Fuel and Power for Compressor Stations						
90	856	Mains Expenses						
91	857	Measuring and Regulating Station Expenses						
92	858	Transmission and Compression of Gas By Others						
93	859	Other Expenses						
94	860	Rents						
95		Total Gas Transmission Operation Expenses						
96	861	Maintenance Supervision and Engineering						
97	862	Maintenance of Structures and Improvements						
98	863	Maintenance of Mains						
99	864	Maintenance of Compressor Station Equipment						
100	865	Maintenance of Measuring And Regulating Station Equipment						
101	866	Maintenance of Communication Equipment						
102	867	Maintenance of Other Equipment						
103		Total Gas Transmission Maintenance Expenses						
104	870-881	Total Distribution Operation Expenses						

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Line No.	Account Number (a)	Title of Account (b)	Associate Company Direct Cost (c)	Associate Company Indirect Cost (d)	Associate Company Total Cost (e)	Nonassociate Company Direct Cost (f)	Nonassociate Company Indirect Cost (g)	Nonassociate Company Total Cost (h)
105	885-894	Total Distribution Maintenance Expenses						
106		Total Natural Gas Operation and Maintenance Expenses						
107	901	Supervision	757,550	1,358,076	2,115,626			
108	902	Meter reading expenses	127,763	646,670	774,433			
109	903	Customer records and collection expenses	44,316,609	27,478,237	71,794,846			
110	904	Uncollectible accounts	3,172	6	3,178			
111	905	Miscellaneous customer accounts expenses	255,067	120,317	375,384			
112	906	Total Customer Accounts Operation Expenses	45,460,161	29,603,306	75,063,467			
113	907	Supervision	2,343,324	1,731,136	4,074,460			
114	908	Customer assistance expenses	4,123,413	524,541	4,647,954			
115	909	Informational And Instructional Advertising Expenses	15,331	27,090	42,421			
116	910	Miscellaneous Customer Service And Informational Expenses	64,904	87,914	152,818	248		248
117		Total Service and Informational Operation Accounts	6,546,972	2,370,681	8,917,653	248		248
118	911	Supervision	227,838	19,626	247,464			
119	912	Demonstrating and Selling Expenses	6,578		6,578			
120	913	Advertising Expenses	614	479	1,093			
121	916	Miscellaneous Sales Expenses						
122		Total Sales Operation Expenses	235,030	20,105	255,135			
123	920	Administrative and General Salaries	149,735,886	70,294,754	220,030,640	2,271,170	229,857	2,501,027
124	921	Office Supplies and Expenses	14,451,853	14,361,343	28,813,196	89,763	22,254	112,017
125	923	Outside Services Employed	629,917	21,299,666	21,929,583	1,662,518	15,928	1,678,446
126	924	Property Insurance	116,082	49,967	166,049			
127	925	Injuries and Damages	5,336,225	40,319	5,376,544			
128	926	Employee Pensions and Benefits	158,150,746	50,784	158,201,530			
129	928	Regulatory Commission Expenses	1,503,089	239,797	1,742,886			
130	930 1	General Advertising Expenses	1,750,129	104,605	1,854,734			
131	930 2	Miscellaneous General Expenses	5,292,616	1,347,817	6,640,433			
132	931	Rents	26,069,773	20,222,906	46,292,679			
133		Total Administrative and General Operation Expenses	363,036,316	128,011,958	491,048,274	4,023,451	268,039	4,291,490
134	935	Maintenance of Structures and Equipment	36,123,095	30,227,865	66,350,960	127		127
135		Total Administrative and General Maintenance Expenses	451,401,574	190,233,915	641,635,489	4,023,826	268,039	4,291,865
136		Total Cost of Service	936,987,145	287,847,845	1,224,834,990	5,764,888	452,171	6,217,059

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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
1	403-403.1	Depreciation Expense	2,594,438	2,025,429	4,619,867
2	404-405	Amortization Expense	398,603	219,517	618,120
3	407.3-407.4	Regulatory Debits/Credits -- Net			
4	408.1-408.2	Taxes Other Than Income Taxes	43,765,319	1,115,970	44,881,289
5	409.1-409.3	Income Taxes	(46,610,593)		(46,610,593)
6	410.1-411.2	Provision for Deferred Taxes	147,805,248		147,805,248
7	411.1-411.2	Provision for Deferred Taxes -- Credit	89,201,750		89,201,750
8	411.6	Gain from Disposition of Service Company Plant			
9	411.7	Losses from Disposition of Service Company Plant			
10	411.4-411.5	Investment Tax Credit Adjustment	50,808		50,808
11	411.10	Accretion Expense			
12	412	Costs and Expenses of Construction or Other Services	219,544,055	32,784,429	252,328,484
13	416	Costs and Expenses of Merchandising, Jobbing, and Contract Work for Associated Companies			
14	418	Non-operating Rental Income			
15	418.1	Equity in Earnings of Subsidiary Companies			
16	419	Interest and Dividend Income	122		122
17	419.1	Allowance for Other Funds Used During Construction			
18	421	Miscellaneous Income or Loss	627,696	277,646	905,342
19	421.1	Gain on Disposition of Property			
20	421.2	Loss on Disposition Of Property	10,869,176		10,869,176
21	425	Miscellaneous Amortization			
22	426.1	Donations	1,652,373		1,652,373
23	426.2	Life Insurance			
24	426.3	Penalties	31,094		31,094
25	426.4	Expenditures for Certain Civic, Political and Related Activities	4,974,575	312,058	5,286,633
26	426.5	Other Deductions	2,744,204	662,147	3,406,351
27	427	Interest On Long-Term Debt			
28	428	Amortization of Debt Discount and Expense			
29	429	Amortization of Premium on Debt -- Credit			
30	430	Interest on Debt to Associate Companies	364,670		364,670
31	431	Other Interest Expense	(109,854)		(109,854)
32	432	Allowance for Borrowed Funds Used During Construction	(578)		(578)
33	500-509	Total Steam Power Generation Operation Expenses	65,637,567	11,246,486	76,884,053
34	510-515	Total Steam Power Generation Maintenance Expenses	23,650,649	4,340,883	27,991,532

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
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Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
35	517-525	Total Nuclear Power Generation Operation Expenses	160,872	571,888	732,760
36	528-532	Total Nuclear Power Generation Maintenance Expenses	1,109,843	422,160	1,532,003
37	535-540.1	Total Hydraulic Power Generation Operation Expenses	1,287,766	521,206	1,808,972
38	541-545.1	Total Hydraulic Power Generation Maintenance Expenses	503,596	236,390	739,986
39	546-550.1	Total Other Power Generation Operation Expenses	293,003	97,822	390,825
40	551-554.1	Total Other Power Generation Maintenance Expenses	32,649	5,019	37,668
41	555-557	Total Other Power Supply Operation Expenses	22,708,912	15,170,231	37,879,143
42	560	Operation Supervision and Engineering	10,370,461	3,482,813	13,853,274
43	561.1	Load Dispatch-Reliability	82,526	160,174	242,700
44	561.2	Load Dispatch-Monitor and Operate Transmission System	4,025,911	5,285,243	9,311,154
45	561.3	Load Dispatch-Transmission Service and Scheduling	(52,675)	101,715	49,040
46	561.4	Scheduling, System Control and Dispatch Services	45,888		45,888
47	561.5	Reliability Planning and Standards Development	635,673	686,866	1,322,539
48	561.6	Transmission Service Studies			
49	561.7	Generation Interconnection Studies			
50	561.8	Reliability Planning and Standards Development Services			
51	562	Station Expenses (Major Only)	76,376	15,512	91,888
52	563	Overhead Line Expenses (Major Only)	47,118	13,737	60,855
53	564	Underground Line Expenses (Major Only)			
54	565	Transmission of Electricity by Others (Major Only)			
55	566	Miscellaneous Transmission Expenses (Major Only)	23,446,996	1,402,127	24,849,123
56	567	Rents	600		600
57	567.1	Operation Supplies and Expenses (Nonmajor Only)			
58		Total Transmission Operation Expenses	38,678,874	11,148,187	49,827,061
59	568	Maintenance Supervision and Engineering (Major Only)	616,346	156,634	772,980
60	569	Maintenance of Structures (Major Only)	1,711	136	1,847
61	569.1	Maintenance of Computer Hardware	30,957	67,850	98,807
62	569.2	Maintenance of Computer Software	1,698,527	1,397,150	3,095,677
63	569.3	Maintenance of Communication Equipment	832	45,735	46,567
64	569.4	Maintenance of Miscellaneous Regional Transmission Plant			
65	570	Maintenance of Station Equipment (Major Only)	1,281,256	329,741	1,610,997
66	571	Maintenance of Overhead Lines (Major Only)	417,555	921,917	1,339,472
67	572	Maintenance of Underground Lines (Major Only)	1,437	412	1,849
68	573	Maintenance of Miscellaneous Transmission Plant (Major Only)	5,451	227	5,678

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
69	574	Maintenance of Transmission Plant (Nonmajor Only)			
70		Total Transmission Maintenance Expenses	4,054,072	2,919,802	6,973,874
71	575.1-575.8	Total Regional Market Operation Expenses			
72	576.1-576.5	Total Regional Market Maintenance Expenses			
73	580-589	Total Distribution Operation Expenses	29,715,066	13,564,405	43,279,471
74	590-598	Total Distribution Maintenance Expenses	1,351,410	711,679	2,063,089
75		Total Electric Operation and Maintenance Expenses	487,326,633	97,798,062	585,124,695
76	700-798	Production Expenses (Provide selected accounts in a footnote)			
77	800-813	Total Other Gas Supply Operation Expenses			
78	814-826	Total Underground Storage Operation Expenses			
79	830-837	Total Underground Storage Maintenance Expenses			
80	840-842.3	Total Other Storage Operation Expenses			
81	843.1-843.9	Total Other Storage Maintenance Expenses			
82	844.1-846.2	Total Liquefied Natural Gas Terminaling and Processing Operation Expenses			
83	847.1-847.8	Total Liquefied Natural Gas Terminaling and Processing Maintenance Expenses			
84	850	Operation Supervision and Engineering			
85	851	System Control and Load Dispatching			
86	852	Communication System Expenses			
87	853	Compressor Station Labor and Expenses			
88	854	Gas for Compressor Station Fuel			
89	855	Other Fuel and Power for Compressor Stations			
90	856	Mains Expenses			
91	857	Measuring and Regulating Station Expenses			
92	858	Transmission and Compression of Gas By Others			
93	859	Other Expenses			
94	860	Rents			
95		Total Gas Transmission Operation Expenses			
96	861	Maintenance Supervision and Engineering			
97	862	Maintenance of Structures and Improvements			
98	863	Maintenance of Mains			
99	864	Maintenance of Compressor Station Equipment			
100	865	Maintenance of Measuring And Regulating Station Equipment			
101	866	Maintenance of Communication Equipment			
102	867	Maintenance of Other Equipment			
103		Total Gas Transmission Maintenance Expenses			
104	870-881	Total Distribution Operation Expenses			

Name of Respondent American Electric Power Service Corporation	This Report Is: (1) [X] An Original (2) [ ] A Resubmission	Resubmission Date (Mo, Da, Yr) / /	Year/Period of Report Dec 31, 2010

Schedule XVI- Analysis of Charges for Service- Associate and Non-Associate Companies (continued)

Line No.	Account Number (a)	Title of Account (b)	Total Charges for Services Direct Cost (i)	Total Charges for Services Indirect Cost (j)	Total Charges for Services Total Cost (k)
105	885-894	Total Distribution Maintenance Expenses			
106		Total Natural Gas Operation and Maintenance Expenses			
107	901	Supervision	757,550	1,358,076	2,115,626
108	902	Meter reading expenses	127,763	646,670	774,433
109	903	Customer records and collection expenses	44,316,609	27,478,237	71,794,846
110	904	Uncollectible accounts	3,172	6	3,178
111	905	Miscellaneous customer accounts expenses	255,067	120,317	375,384
112	906	Total Customer Accounts Operation Expenses	45,460,161	29,603,306	75,063,467
113	907	Supervision	2,343,324	1,731,136	4,074,460
114	908	Customer assistance expenses	4,123,413	524,541	4,647,954
115	909	Informational And Instructional Advertising Expenses	15,331	27,090	42,421
116	910	Miscellaneous Customer Service And Informational Expenses	65,152	87,914	153,066
117		Total Service and Informational Operation Accounts	6,547,220	2,370,681	8,917,901
118	911	Supervision	227,838	19,626	247,464
119	912	Demonstrating and Selling Expenses	6,578		6,578
120	913	Advertising Expenses	614	479	1,093
121	916	Miscellaneous Sales Expenses			
122		Total Sales Operation Expenses	235,030	20,105	255,135
123	920	Administrative and General Salaries	152,007,056	70,524,611	222,531,667
124	921	Office Supplies and Expenses	14,541,616	14,383,597	28,925,213
125	923	Outside Services Employed	2,292,435	21,315,594	23,608,029
126	924	Property Insurance	116,082	49,967	166,049
127	925	Injuries and Damages	5,336,225	40,319	5,376,544
128	926	Employee Pensions and Benefits	158,150,746	50,784	158,201,530
129	928	Regulatory Commission Expenses	1,503,089	239,797	1,742,886
130	930.1	General Advertising Expenses	1,750,129	104,605	1,854,734
131	930.2	Miscellaneous General Expenses	5,292,616	1,347,817	6,640,433
132	931	Rents	26,069,773	20,222,906	46,292,679
133		Total Administrative and General Operation Expenses	367,059,767	128,279,997	495,339,764
134	935	Maintenance of Structures and Equipment	36,123,222	30,227,865	66,351,087
135		Total Administrative and General Maintenance Expenses	455,425,400	190,501,954	645,927,354
136		Total Cost of Service	942,752,033	288,300,016	1,231,052,049

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XVII - Analysis of Billing – Associate Companies (Account 457)

1. For services rendered to associate companies (Account 457), list all of the associate companies.

Line No	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	AEP Appalachian Transmission Company, Inc	404,568	62,896	(1,831)	465,633
2	AEP C&I Company LLC	32,669	30,868	(1,437)	62,100
3	AEP Coal, Inc.	75,400	16,172		91,572
4	AEP Credit, Inc.	306,243	63,569	4,561	374,373
5	AEP Desert Sky GP, LLC	996	147		1,143
6	AEP Elmwood LLC	1,720	234,872		236,592
7	AEP Energy Partners, Inc.	3,078,316	1,393,419		4,471,735
8	AEP Energy Service Gas Holding Company	88,241	4,765		93,006
9	AEP Energy Services, Inc.	793,986	162,645	17,722	974,353
10	AEP Fiber Venture, LLC	869	177		1,046
11	AEP Generating Company	9,047,280	1,821,070	71,881	10,940,231
12	AEP Indiana Michigan Transmission Company, Inc.	1,576,315	265,633	2,990	1,844,938
13	AEP Investments, Inc.	57,975	10,888	3,161	72,024
14	AEP Kentucky Coal, LLC	249,526	57,014		306,540
15	AEP Kentucky Transmission Company, Inc.	137,219	21,702	16	158,937
16	AEP Nonutility Funding LLC	15,606	5,544	220	21,370
17	AEP Ohio Transmission Company, Inc.	1,750,159	279,462	(8,406)	2,021,215
18	AEP Oklahoma Transmission Company, Inc.	992,661	143,723	(2,672)	1,133,712
19	AEP Pro Serv, Inc.	714,802	184,991	8,119	907,912
20	AEP Resources, Inc.	357,565	91,844	7,469	456,878
21	AEP Retail Energy Partners LLC	268,074	117,427		385,501
22	AEP River Operations LLC	943,249	1,731,080		2,674,329
23	AEP Southwestern Transmission Company, Inc	43,027	5,098	604	48,729
24	AEP System Pool	644,665	298,613		943,278
25	AEP T&D Services, LLC	4,153,083	746,028	48,194	4,947,305
26	AEP Texas C&I Retail GP, LLC	1,414	263		1,677
27	AEP Texas C&I Retail LP	20,670	4,823		25,493
28	AEP Texas Central Company	54,609,319	20,538,891	782,765	75,930,975
29	AEP Texas North Company	25,674,974	7,761,538	306,069	33,742,581
30	AEP Transmission Company, LLC	1,081,744	146,149	25,535	1,253,428
31	AEP Transmission Holding Company, LLC	2,696,436	484,048	30,618	3,211,102
32	AEP TX North Generation Company, LLC	38,388	6,039		44,427
33	AEP Utilities, Inc.	1,862,123	252,630	46,405	2,161,158
34	AEP Utility Funding LLC	476,433	119,139	5,952	601,524
35	AEP West Virginia Transmission Company, Inc.	831,627	128,074	(4,575)	955,126
36	AEP Wind Holding Company, LLC	415,891	103,584	8,900	528,375
37	AEPES US Gas Trading	22,916	4,607		27,523
38	American Electric Power Company	15,219,198	4,791,645	103,013	20,113,856
39	Appalachian Power Company	182,388,850	53,548,318	2,411,892	238,349,060

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XVII - Analysis of Billing -- Associate Companies (Account 457) (continued)

Line No.	Name of Associate Company (a)	Account 457.1 Direct Costs Charged (b)	Account 457.2 Indirect Costs Charged (c)	Account 457.3 Compensation For Use of Capital (d)	Total Amount Billed (e)
1	Blackhawk Coal Company	12,836	2,718		15,554
2	Cardinal Operating Company	19,600,193	4,263,424	221,434	24,085,051
3	Cedar Coal Company	4,091	1,160		5,251
4	Central Appalachian Coal Company	2,673	665		3,338
5	Central Coal Company	3,131	826		3,957
6	Columbus Southern Power Company	103,213,349	31,348,860	1,347,922	135,910,131
7	Conesville Coal Preparation Company	138,918	108,060	2,444	249,422
8	CSW Energy Services, Inc	15,469	4,378	589	20,436
9	CSW Energy, Inc.	723,858	168,781	15,403	908,042
10	Desert Sky Wind Farm LP	198,785	43,933		242,718
11	Diversified Ergy Contr LLC	55	13		68
12	Dolet Hills Lignite Co, LLC	1,393,106	366,071		1,759,177
13	Electric Transmission America	5,180	1,771	22	6,973
14	Electric Transmission TX, LLC	12,483,563	1,587,917	154,523	14,226,003
15	Franklin Real Estate Company	1,334	369		1,703
16	Indiana Franklin Realty, Inc	942	84		1,026
17	Indiana Michigan Power Company	97,615,484	40,940,587	1,348,199	139,904,270
18	Kentucky Power Company	27,469,838	9,232,313	360,987	37,063,138
19	Kingsport Power Company	3,411,228	1,301,769	48,979	4,761,976
20	Mutual Energy SWEPCO L.P	70	16		86
21	Ohio Power Company	151,270,936	43,158,675	1,841,766	196,271,377
22	Oxbow Lignite Company, LLC	57,804	12,036		69,840
23	Public Service Company of Oklahoma	75,932,014	25,352,017	831,850	102,115,881
24	REP General Partner LLC	1,934	480		2,414
25	REP Holdco Inc	2,726	659		3,385
26	Snowcap Coal Company, Inc	17,948	3,932		21,880
27	Southern Appalachian Coal Company	4,327	1,169		5,496
28	Southwestern Electric Power Company	113,784,498	32,800,173	1,343,125	147,927,796
29	Trent Wind Farm LP	215,293	42,695		257,988
30	United Sciences Testing, Inc.	3,387,511	236,975	44,959	3,669,445
31	Wheeling Power Company	3,472,313	1,225,924	42,174	4,740,411
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40	**Total**	**925,515,604**	**287,847,845**	**11,471,541**	**1,224,834,990**

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XVIII – Analysis of Billing – Non-Associate Companies (Account 458)

1. For services rendered to nonassociate companies (Account 458), list all of the nonassociate companies. In a footnote, describe the services rendered to each respective nonassociate company.

Line No.	Name of Non-associate Company (a)	Account 458.1 Direct Costs Charged (b)	Account 458.2 Indirect Costs Charged (c)	Account 458.3 Compensation For Use of Capital (d)	Account 458.4 Excess or Deficiency on Servicing Non-associate Utility Companies (e)	Total Amount Billed (f)
1	CG&E/Zimmer Services Agreement	3,223				3,223
2	Duke Energy - Ohio	599	110			709
3	Dayton Power & Light	179,139	4,709			183,848
4	Indiana Kentucky Electric Company	2,507,581	199,202			2,706,783
5	Ohio Valley Electric Company	3,074,346	248,150			3,322,496
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40	**Total**	**5,764,888**	**452,171**			**6,217,059**

Schedule Page: 308 Line No.: 40 Column: f

CG&E/Zimmer Services Agreement

The services provided to CG&E/Zimmer Services Agreement are the result of allocated Simulator Learning Center and Operator Training Costs.

Duke Energy - Ohio

The services provided to Duke Energy - Ohio are the result of Relative Accuracy Test Audits and labor, labor fringes and other employee expenses for Zimmer Plant.

Dayton Power & Light

The services provided to Dayton Power & Light are primarily the result of Relative Accuracy Test Audits at Stuart Plant.

Indiana Kentucky Electric Company

The services provided to Indiana Kentucky Electric Company are primarily the result of labor, labor fringes and contract labor for Clifty Creek.

Ohio Valley Electric Company

The services provided to Ohio Valley Electric Company are primarily the result of labor, labor fringes and contract labor for Kyger Creek.

Name of Respondent	This Report Is:	Resubmission Date (Mo, Da, Yr)	Year/Period of Report
American Electric Power Service Corporation	(1) [X] An Original (2) [ ] A Resubmission	/ /	Dec 31, 2010

Schedule XIX - Miscellaneous General Expenses - Account 930.2

1. Provide a listing of the amount included in Account 930.2, "Miscellaneous General Expenses" classifying such expenses according to their nature. Amounts less than $50,000 may be grouped showing the number of items and the total for the group.
2. Payments and expenses permitted by Section 321 (b)(2) of the Federal Election Campaign Act, as amended by Public Law 94-283 in 1976 (2 U.S.C. 441(b)(2)) shall be separately classified.

Line No.	Title of Account (a)	Amount (b)
1	Salaries, Salary related Expense and Overheads	1,443,937
2	Membership Fees and Dues	3,783,646
3	Outside Professional Services	380,946
4	Employee Expenses	150,584
5	Legal Expenses	112,500
6	Materials and Supplies	242,265
7	Telephone and Communication Expenses	117,726
8	Contributions	81,190
9	Fleet Services	273,357
10	Other - 7 Items	60,282
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40	**Total**	6,646,433

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
American Electric Power Service Corporation	(1) X An Original (2) __ A Resubmission	/ /	2010

Schedule XX - Organization Chart

1 Provide a graphical presentation of the relationships and inter relationships within the service company that identifies lines of authority and responsibility in the organization.

Commercial Operations
- Commercial & Financial Analysis
- Commercial Operations
- Energy Trading & Marketing
- Generation Dispatch
- RTO Operations

Finance, Accounting and Strategic Planning
- Corporate Accounting
- Corporate Planning and Budgeting
- Finance, Accounting and Strategic Planning Administration
- Risk and Strategic Initiatives
- Treasury and Investor Relations

Generation
- Fossil and Hydro Generation
- Fuel, Emissions and Logistics
- Generation Administration
- Generation Business Services
- Generation Engineering and Technical Services - Engineering Project Field Services

Office of the Chairman
- Audit Services
- Chief Executive Officer - Ovec/Ikec
- Corporate Communications
- Federal Affairs
- Legal General Counsel Administration
- Office of the Chairman

Shared Services
- Business Logistics
- Corporate Human Resources
- Information Technology
- Shared Services

Transmission
- Electric Transmission Texas
- Transmission Administration
- Transmission Engineering and Project Services
- Transmission Region Operations
- Transmission Reliability Compliance
- Transmission Strategy and Business Development
- Transmission System Operations

Utility Operations
- Customer and Distribution Services
- Environment and Safety
- Regulatory Services

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
American Electric Power Service Corporation	(1) X An Original (2) __ A Resubmission	/ /	2010

Schedule XX - Organization Chart

Utility Operations Business Services
Utility Operations East
Utility Operations West
Vice Chairman
Utility Operations Administration

Name of Respondent	This Report is:	Resubmission Date (Mo, Da, Yr)	Year of Report
American Electric Power Service Corporation	(1) X An Original (2) __ A Resubmission	/ /	2010

Schedule XXI - Methods of Allocation

1. Indicate the service department or function and the basis for allocation used when employees render services to more than one department or functional group. If a ratio, include the numerator and denominator
2. Include any other allocation methods used to allocate costs.

1. The table below contains the service department or function and the basis for allocation used when employees render services to more than one department or functional group. The second table contains the allocation factor definitions and the numerator and denominator for each allocation factor.

COMMERCIAL OPERATIONS	
Service Department or Function	**Basis of Allocation**
Commercial & Financial Analysis	28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year) 77 Daily Power Transactions (All Markets) 78 Power Transactions to ERCOT Market 79 Daily Gas Transactions (All Markets)
Commercial Operations	8 Number of Electric Retail Customers 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 48 MW Generating Capability 49 MWH's Generated 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 64 Total Peak Load (Prior Year)
Energy Trading & Marketing	37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 48 MW Generating Capability 49 MWH's Generated 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 64 Total Peak Load (Prior Year)
Generation Dispatch	28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 48 MW Generating Capability 49 MWH's Generated 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 64 Total Peak Load (Prior Year)

RTO Operations	37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 48 MW Generating Capability 49 MWH's Generated 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 64 Total Peak Load (Prior Year)

FINANCE, ACCOUNTING AND STRATEGIC PLANNING

Service Department or Function	Basis of Allocation
Corporate Accounting	5 Number of CIS Customer Mailings 8 Number of Electric Retail Customers 9 Number of Employees 11 Number of General Ledger (GL) Transactions 12 Number of Help Desk Calls 15 Number of Non-United Mine Workers of America (UMWA) Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 20 Number of Remittance Items 26 Number of Stores Transactions 28 Number of Transmission Pole Miles 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 48 MW Generating Capability 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 63 Total Gross Utility Plant (Including CWIP) 64 Total Peak Load (Prior Year) 67 Number of Banking Transactions 70 Number of Nonelectric Other Accounts Receivable (OAR) Invoices
Corporate Planning and Budgeting	8 Number of Electric Retail Customers 9 Number of Employees 11 Number of General Ledger (GL) Transactions 15 Number of Non-United Mine Workers of America (UMWA) Employees 26 Number of Stores Transactions 28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 44 Level of Construction - Distribution 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 51 Past 3 Mo. MMBTU's Burned (All Fuel Types)

	57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year)
Finance, Accounting and Strategic Planning Administration	5 Number of CIS Customer Mailings 8 Number of Electric Retail Customers 9 Number of Employees 11 Number of General Ledger (GL) Transactions 15 Number of Non-United Mine Workers of America (UMWA) Employees 26 Number of Stores Transactions 28 Number of Transmission Pole Miles 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 44 Level of Construction - Distribution 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year) 67 Number of Banking Transactions 70 Number of Nonelectric Other Accounts Receivable (OAR) Invoices 77 Daily Power Transactions (All Markets)
Risk and Strategic Initiatives	8 Number of Electric Retail Customers 9 Number of Employees 15 Number of Non-United Mine Workers of America (UMWA) Employees 17 Number of Purchase Orders Written 26 Number of Stores Transactions 28 Number of Transmission Pole Miles 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 45 Level of Construction - Production 48 MW Generating Capability 49 MWH's Generated 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year) 77 Daily Power Transactions (All Markets) 79 Daily Gas Transactions (All Markets)
Treasury and Investor Relations	9 Number of Employees

	37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 45 Level of Construction - Production 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year) 67 Number of Banking Transactions

GENERATION	
Service Department or Function	**Basis of Allocation**
Fossil and Hydro Generation	8 Number of Electric Retail Customers 9 Number of Employees 17 Number of Purchase Orders Written 28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 64 Total Peak Load (Prior Year)
Fuel, Emissions and Logistics	9 Number of Employees 11 Number of General Ledger (GL) Transactions 17 Number of Purchase Orders Written 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 45 Level of Construction - Production 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 53 Past 3 Mo. MMBTU's Burned (Gas Type Only) 55 Past 3 mo. MMBTU's Burned (Solid Fuels Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year)
Generation Administration	37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 45 Level of Construction - Production 48 MW Generating Capability 49 MWH's Generated

	51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 55 Past 3 mo. MMBTU's Burned (Solid Fuels Only) 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets
Generation Business Services	9 Number of Employees 17 Number of Purchase Orders Written 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 44 Level of Construction - Distribution 45 Level of Construction - Production 48 MW Generating Capability 49 MWH's Generated 52 Past 3 Mo. MMBTU's Burned (Coal Only) 53 Past 3 Mo. MMBTU's Burned (Gas Type Only) 55 Past 3 mo. MMBTU's Burned (Solid Fuels Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year) 70 Number of Nonelectric Other Accounts Receivable (OAR) Invoices
Generation Engineering and Technical Services - Engineering Project Field Services	8 Number of Electric Retail Customers 9 Number of Employees 17 Number of Purchase Orders Written 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 45 Level of Construction - Production 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 55 Past 3 mo. MMBTU's Burned (Solid Fuels Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year)

OFFICE OF THE CHAIRMAN

Service Department or Function	Basis of Allocation
Audit Services	8 Number of Electric Retail Customers 9 Number of Employees 15 Number of Non-United Mine Workers of America (UMWA) Employees 17 Number of Purchase Orders Written 28 Number of Transmission Pole Miles

	37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 63 Total Gross Utility Plant (Including CWIP) 64 Total Peak Load (Prior Year)
Chief Executive Officer - Ovec/Ikec	39 Direct 48 MW Generating Capability 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs
Corporate Communications	8 Number of Electric Retail Customers 9 Number of Employees 15 Number of Non-United Mine Workers of America (UMWA) Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 26 Number of Stores Transactions 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 48 MW Generating Capability 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets
Federal Affairs	8 Number of Electric Retail Customers 9 Number of Employees 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs
Legal General Counsel Administration	8 Number of Electric Retail Customers 9 Number of Employees 12 Number of Help Desk Calls 15 Number of Non-United Mine Workers of America (UMWA) Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 26 Number of Stores Transactions 28 Number of Transmission Pole Miles 30 Number of Travel Transactions 32 Number of Vendor Invoice Payments 33 Number of Workstations 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 44 Level of Construction - Distribution 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types)

	52 Past 3 Mo. MMBTU's Burned (Coal Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year) 65 Hydro MW Generating Capability
Office of the Chairman	8 Number of Electric Retail Customers 9 Number of Employees 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 52 Past 3 Mo. MMBTU's Burned (Coal Only) 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs

SHARED SERVICES

Service Department or Function	Basis of Allocation
Business Logistics	5 Number of CIS Customer Mailings 6 Number of Commercial Customers 8 Number of Electric Retail Customers 9 Number of Employees 11 Number of General Ledger (GL) Transactions 12 Number of Help Desk Calls 15 Number of Non-United Mine Workers of America (UMWA) Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 20 Number of Remittance Items 23 Number of Residential Customers 26 Number of Stores Transactions 27 Number of Telephones 28 Number of Transmission Pole Miles 30 Number of Travel Transactions 31 Number of Vehicles 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 43 KWH Sales 44 Level of Construction - Distribution 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 53 Past 3 Mo. MMBTU's Burned (Gas Type Only) 55 Past 3 mo. MMBTU's Burned (Solid Fuels Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs

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	61 Total Fixed Assets 63 Total Gross Utility Plant (Including CWIP) 64 Total Peak Load (Prior Year) 65 Hydro MW Generating Capability 66 Number of Forest Acres 67 Number of Banking Transactions 70 Number of Nonelectric Other Accounts Receivable (OAR) Invoices
Corporate Human Resources	5 Number of CIS Customer Mailings 6 Number of Commercial Customers 8 Number of Electric Retail Customers 9 Number of Employees 11 Number of General Ledger (GL) Transactions 12 Number of Help Desk Calls 15 Number of Non-United Mine Workers of America (UMWA) Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 20 Number of Remittance Items 23 Number of Residential Customers 26 Number of Stores Transactions 27 Number of Telephones 28 Number of Transmission Pole Miles 30 Number of Travel Transactions 31 Number of Vehicles 32 Number of Vendor Invoice Payments 33 Number of Workstations 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 43 KWH Sales 44 Level of Construction - Distribution 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 53 Past 3 Mo. MMBTU's Burned (Gas Type Only) 55 Past 3 mo. MMBTU's Burned (Solid Fuels Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 63 Total Gross Utility Plant (Including CWIP) 64 Total Peak Load (Prior Year) 65 Hydro MW Generating Capability 66 Number of Forest Acres 67 Number of Banking Transactions 70 Number of Nonelectric Other Accounts Receivable (OAR) Invoices
Information Technology	5 Number of CIS Customer Mailings 6 Number of Commercial Customers 8 Number of Electric Retail Customers 9 Number of Employees 11 Number of General Ledger (GL) Transactions

	12 Number of Help Desk Calls 13 Number of Industrial Customers 15 Number of Non-United Mine Workers of America (UMWA) Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 20 Number of Remittance Items 23 Number of Residential Customers 26 Number of Stores Transactions 27 Number of Telephones 28 Number of Transmission Pole Miles 30 Number of Travel Transactions 31 Number of Vehicles 32 Number of Vendor Invoice Payments 33 Number of Workstations 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 43 KWH Sales 44 Level of Construction - Distribution 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 53 Past 3 Mo. MMBTU's Burned (Gas Type Only) 55 Past 3 mo. MMBTU's Burned (Solid Fuels Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 63 Total Gross Utility Plant (Including CWIP) 64 Total Peak Load (Prior Year) 65 Hydro MW Generating Capability 66 Number of Forest Acres 67 Number of Banking Transactions 70 Number of Nonelectric Other Accounts Receivable (OAR) Invoices 77 Daily Power Transactions (All Markets) 78 Power Transactions to ERCOT Market 79 Daily Gas Transactions (All Markets)
Shared Services	9 Number of Employees 17 Number of Purchase Orders Written 26 Number of Stores Transactions 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 46 Level of Construction - Transmission 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year)

TRANSMISSION

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Schedule XXI - Methods of Allocation

Service Department or Function	Basis of Allocation
Electric Transmission Texas	9 Number of Employees 28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs
Transmission Administration	8 Number of Electric Retail Customers 9 Number of Employees 17 Number of Purchase Orders Written 28 Number of Transmission Pole Miles 30 Number of Travel Transactions 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 46 Level of Construction - Transmission 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets
Transmission Engineering and Project Services	8 Number of Electric Retail Customers 9 Number of Employees 28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 43 KWH Sales 45 Level of Construction - Production 46 Level of Construction - Transmission 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets
Transmission Region Operations	8 Number of Electric Retail Customers 9 Number of Employees 15 Number of Non-United Mine Workers of America (UMWA) Employees 17 Number of Purchase Orders Written 28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 46 Level of Construction - Transmission 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets
Transmission Reliability Compliance	28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 43 KWH Sales 46 Level of Construction - Transmission 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets

Transmission Strategy and Business Development	8 Number of Electric Retail Customers 9 Number of Employees 17 Number of Purchase Orders Written 26 Number of Stores Transactions 28 Number of Transmission Pole Miles 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 43 KWH Sales 46 Level of Construction - Transmission 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 67 Number of Banking Transactions
Transmission System Operations	5 Number of CIS Customer Mailings 8 Number of Electric Retail Customers 9 Number of Employees 15 Number of Non-United Mine Workers of America (UMWA) Employees 17 Number of Purchase Orders Written 28 Number of Transmission Pole Miles 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 44 Level of Construction - Distribution 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 63 Total Gross Utility Plant (Including CWIP) 64 Total Peak Load (Prior Year)

UTILITY OPERATIONS

Service Department or Function	Basis of Allocation
Customer and Distribution Services	5 Number of CIS Customer Mailings 6 Number of Commercial Customers 8 Number of Electric Retail Customers 9 Number of Employees 12 Number of Help Desk Calls 13 Number of Industrial Customers 15 Number of Non-United Mine Workers of America (UMWA) Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 20 Number of Remittance Items 26 Number of Stores Transactions 28 Number of Transmission Pole Miles 30 Number of Travel Transactions

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	31 Number of Vehicles 32 Number of Vendor Invoice Payments 33 Number of Workstations 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 44 Level of Construction - Distribution 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 70 Number of Nonelectric Other Accounts Receivable (OAR) Invoices
Environment and Safety	8 Number of Electric Retail Customers 9 Number of Employees 15 Number of Non-United Mine Workers of America (UMWA) Employees 17 Number of Purchase Orders Written 23 Number of Residential Customers 28 Number of Transmission Pole Miles 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 44 Level of Construction - Distribution 45 Level of Construction - Production 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 55 Past 3 mo. MMBTU's Burned (Solid Fuels Only) 57 Tons of Fuel Acquired 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 64 Total Peak Load (Prior Year) 66 Number of Forest Acres
Regulatory Services	8 Number of Electric Retail Customers 9 Number of Employees 11 Number of General Ledger (GL) Transactions 15 Number of Non-United Mine Workers of America (UMWA) Employees 17 Number of Purchase Orders Written 28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 45 Level of Construction - Production 48 MW Generating Capability 51 Past 3 Mo. MMBTU's Burned (All Fuel Types) 52 Past 3 Mo. MMBTU's Burned (Coal Only) 57 Tons of Fuel Acquired

	58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 63 Total Gross Utility Plant (Including CWIP) 64 Total Peak Load (Prior Year)
Utility Operations Business Services	8 Number of Electric Retail Customers 9 Number of Employees 39 Direct 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets
Utility Operations East	6 Number of Commercial Customers 8 Number of Electric Retail Customers 9 Number of Employees 12 Number of Help Desk Calls 15 Number of Non-United Mine Workers of America (UMWA) Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 20 Number of Remittance Items 26 Number of Stores Transactions 27 Number of Telephones 28 Number of Transmission Pole Miles 30 Number of Travel Transactions 32 Number of Vendor Invoice Payments 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 44 Level of Construction - Distribution 46 Level of Construction - Transmission 48 MW Generating Capability 49 MWH's Generated 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets 63 Total Gross Utility Plant (Including CWIP) 64 Total Peak Load (Prior Year)
Utility Operations West	8 Number of Electric Retail Customers 9 Number of Employees 16 Number of Phone Center Calls 17 Number of Purchase Orders Written 28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 40 Equal Share Ratio 46 Level of Construction - Transmission 48 MW Generating Capability 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets
Vice Chairman	8 Number of Electric Retail Customers 9 Number of Employees

	28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 46 Level of Construction - Transmission 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs
Utility Operations Administration	8 Number of Electric Retail Customers 9 Number of Employees 28 Number of Transmission Pole Miles 37 AEPSC Past 3 Months Total Bill Dollars 39 Direct 48 MW Generating Capability 58 Total Assets 60 Total AEPSC Bill Dollars Less Interest and/or Income Taxes and/or other indirect costs 61 Total Fixed Assets

The table below contains the allocation factor definitions and the numerator and denominator for each allocation factor.

ALLOCATION FACTOR	CALCULATION DESCRIPTION	STATUS
1 Number of Bank Accounts	Number of Bank Accounts Per Company Total Number of Bank Accounts	INACTIVE
2 Number of Call Center Telephones	Number of Call Center Telephones Per Company Total Number of Call Center Telephones	INACTIVE
3 Number of Cell Phones / Pagers	Number of Cell Phones / Pagers Per Company Total Number of Cell Phones / Pagers	ACTIVE
4 Number of Checks Printed	Number of Checks Printed Per Company Per Month Total Number of Checks Printed Per Month	INACTIVE
5 Number of CIS Customer Mailings	Number of Customer Information System (CIS) Customer Mailings Per Company Total Number of CIS Customers Mailings	ACTIVE
6 Number of Commercial Customers	Number of Commercial Customers Per Company Total Number of Commercial Customers	ACTIVE
7 Number of Credit Cards	Number of Credit Cards Per Company Total Number of Credit Cards	INACTIVE
8 Number of Electric Retail Customers	Number of Electric Retail Customers Per Company Total Number of Electric Retail Customers	ACTIVE
9 Number of Employees	Number of Full-Time and Part-Time Employees Per Company Total Number of Full-Time and Part-Time Employees	ACTIVE
10 Number of Generating Plant Employees	Number of Generating Plant Employees Per Customer Total Number of Generating Plant Employees	INACTIVE

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11 Number of GL Transactions	Number of General Ledger (GL) Transactions Per Company Total Number of GL Transactions	ACTIVE
12 Number of Help Desk Calls	Number of Help Desk Calls Per Company Total Number of Help Desk Calls	ACTIVE
13 Number of Industrial Customers	Number of Industrial Customers Per Company Total Number of Industrial Customers	ACTIVE
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	ACTIVE
16 Number of Phone Center Calls	Number of Phone Calls Per Phone Center Per Company Total Number of Phone Center Phone Calls	ACTIVE
17 Number of Purchase Orders Written	Number of Purchase Orders Written Per Company Total Number of Purchase Orders Written	ACTIVE
18 Number of Radios (Base/Mobile/Handheld)	Number of Radios (Base/Mobile/Handheld) Per Company Total Number of Radios (Base/Mobile/Handheld)	ACTIVE
19 Number of Railcars	Number of Railcars Per Company Total Number of Railcars	ACTIVE
20 Number of Remittance Items	Number of Electric Bill Payments Processed Per Company Per Month (non-lock box) Total Number of Electric Bill Payments Processed Per Month (non-lock box)	ACTIVE
21 Number of Remote Terminal Units	Number of Remote Terminal Units Per Company Total Number of Remote Terminal Units	ACTIVE
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	ACTIVE
24 Number of Routers	Number of 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	ACTIVE
27 Number of Telephones	Number of Telephones Per Company (includes all phone lines) Total Number of Telephones (includes all phone lines)	ACTIVE

28 Number of Transmission Pole Miles	Number of Transmission Pole Miles Per Company Total Number of Transmission Pole Miles	ACTIVE
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	ACTIVE
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)	ACTIVE
32 Number of Vendor Invoice Payments	Number of Vendor Invoice Payments Per Company Per Month Total Number of Vendor Invoice Payments Per Month	ACTIVE
33 Number of Workstations	Number of Workstations (PCs) Per Company Total Number of Workstations (PCs)	ACTIVE
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	ACTIVE
38 AEPSC Prior Month Total Bill Dollars	AEPSC Prior Month Total Bill Dollars Per Company AEPSC Total Prior Month Bill Dollars	ACTIVE
39 Direct	100% to One Company	ACTIVE
40 Equal Share Ratio	One (1) Total Number of Companies	ACTIVE
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 the Last Three Years by the Total Scheduled Maintenance of All Fossil Generating Plants During the Same Three Years Two (2)	INACTIVE

42 Functional Departments 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	ACTIVE
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	ACTIVE
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 Which Charges by AEPSC are Being Made Separately, Per Company During the Last Twelve Months Total of the Same for All Companies	ACTIVE
46 Level of Construction - Transmission	Construction Expenditures for All Transmission Plant Accounts Except Land and Land Rights and Exclusive of Construction Expenditures Accumulated on Direct Work Orders for Which Charges by AEPSC are Being Made Separately, Per Company During the Last Three Months Total of the Same for All Companies	ACTIVE
47 Level of Construction - Total	Construction Expenditures for All Plant Accounts Except Land and Land Rights, Line Transformer 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	ACTIVE
49 MWH's Generated	Number of MWH's Generated Per Company Total Number of MWH's Generated	ACTIVE
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)	ACTIVE
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)	ACTIVE
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)	ACTIVE
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)	ACTIVE
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 Tons of Fuel Acquired	ACTIVE
58 Total Assets	Total Assets Amount Per Company Total Assets Amount	ACTIVE
59 Total Assets Less Nuclear Plant	Total Assets Amount Less Nuclear Assets Per Company Total Assets Amount Less Nuclear Assets	ACTIVE
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	ACTIVE
61 Total Fixed Assets	Total Fixed Assets Amount Per Company Total Fixed Assets Amount	ACTIVE
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 Revenue Last Twelve Months (Including CWIP)	ACTIVE
64 Total Peak Load (Prior Year)	Total Peak Load for Prior Year Per Company Total Peak Load for Prior Year	ACTIVE
65 Hydro MW Generating Capability	Hydro MW Generating Capability Per Company Total Hydro MW Generating Capability	ACTIVE
66 Number of Forest Acres	Number of Forest Acres Per Company Total Number of Forest Acres	ACTIVE

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67 Number of Banking Transactions	Number of Banking Transactions Per Company Total Number of Banking Transactions	ACTIVE
68 Number of Dams	Number of Dams Per Company Total Number of Dams	INACTIVE
69 Number of Plant Licenses Obtained	Number of Plant Licenses Obtained Per Company Number of Plant Licenses Obtained	INACTIVE
70 Number of Nonelectric OAR Invoices	Number of Nonelectric OAR Invoices Per Company Total Number of Nonelectric OAR Invoices	ACTIVE
71 Number of Transformer Transactions	Number of Transformer Transactions Per Company Total Number of Transformer Transactions	ACTIVE
72 Tons of FGD Material	Tons of FGD Material Per Company Total Tons of FGD Material	ACTIVE
73 Tons of Limestone Received	Tons of Limestone Received Per Company Total Tons of Limestone Received	ACTIVE
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 to All Markets by Company Total Number of Power Transactions to All Markets	ACTIVE
78 Power Transactions to ERCOT Market	Power Transactions to ERCOT Market by Company Total Number of Power Transactions to ERCOT Market	ACTIVE
79 Transactions (Commodities) to All Markets	Transactions (Commodities) to all Markets by Company Total Number of Transactions (commodities) to all Markets	ACTIVE
80 Transactions (Commodities) to ERCOT Market	Transactions (Commodities) to ERCOT Market by Company Total Number of Transactions (commodities) to ERCOT Market	ACTIVE

2. The shared services departments (Information Technology, Human Resources, and Business Logistics) use a product billing philosophy where each department has arranged their services into discrete product groups and directly bills the affiliates based on these products. These products have a pre-determined price and each affiliate subscribes to the product based upon their needs. Each affiliate is directly billed for their use of these distinct products.