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Volume I

List of exhibits being filed:

OEG Ex. 101

FES Ex. 104

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IEU Ex 104 Excerpt

Reporter's Signature: Karen Gibson

Date Submitted: 4-17-12

BEFORE THE PUBLIC UTILITIES COMMISSION OF OHIO

- - -

In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company. : Case No. 10-2929-EL-UNC

- - -

PROCEEDINGS

before Ms. Greta See and Ms. Sarah Parrot, Attorney Examiners, and Commissioner Andre Porter, at the Public Utilities Commission of Ohio, 180 East Broad Street, Room 11-A, Columbus, Ohio, called at 10:00 a.m. on Tuesday, April 17, 2012.

- - -

VOLUME I

- - -

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- - -

EXHIBIT

PENGAD 800-631-6989

101

OEG

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

American Electric Power Service Corporation PJM Interconnection, L.L.C.	:	Docket No. ER11-2183-000
American Electric Power Service Corporation	:	
	:	Docket No. EL11-32-000
v.	:	
	:	(not consolidated)
PJM Interconnection, L.L.C.	:	

MOTION FOR LEAVE TO ANSWER AND LIMITED ANSWER
SUBMITTED ON BEHALF OF THE PUBLIC UTILITIES COMMISSION OF OHIO TO PJM INTERCONNECTION, L.L.C. RESPONSE TO AEP MOTION FOR EXPEDITED RULING

March 22, 2012

MOTION FOR LEAVE TO ANSWER

Pursuant to Rules 212 and 213 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC"), The Public Utilities Commission of Ohio ("Ohio Commission" or "PUCO") moves for leave to answer and answers the March 15, 2012 Response of PJM Interconnection, L.L.C. ("PJM Response") in these proceedings. The Ohio Commission respectfully requests that it be permitted to answer the PJM Response, which raises new arguments that PJM has never advanced in these proceedings. Good cause exists to accept the Limited Answer set forth below as it will assist FERC's decision making process.

Respectfully submitted,

/s/ Thomas W. McNamee

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On behalf of
The Public Utilities Commission of Ohio

LIMITED ANSWER

INTRODUCTION AND BACKGROUND

On April 4, 2011, American Electric Power Service Corporation ("AEP") filed a complaint pursuant to Section 206 of the Federal Power Act ("FPA"), 16 U.S.C. § 824e (2006) and Rule 206 of the FERC's Rules of Practice and Procedure, 18 C.F.R. § 385.206 (2010). AEP's complaint, on behalf of Ohio Power Company and the Columbus Southern Power Company ("AEP-Ohio") seeks modifications to Schedule 8.1, Section D.8 to the PJM Interconnection, L.L.C. ("PJM") Reliability Assurance Agreement ("RAA"). AEP's complaint is in response to FERC's order issued on January 20, 2011, in Docket No. ER11-2183.

On February 29, 2012, AEP filed at FERC a Motion for Expedited Ruling alleging that, among other things, the Ohio Commission has implemented the FRR provisions in a manner that is causing the company to incur substantial harm.

On March 15, 2012, PJM filed at FERC its Response to AEP's Motion for Expedited Rulings. In its Response, PJM requests that FERC expeditiously provide the Ohio Commission important guidance to resolve FRR capacity issues that have been in dispute in the State of Ohio for over a year. The Ohio Commission hereby respectfully submits its answer to PJM's Response to AEP's Motion for Expedited Ruling.

DISCUSSION

PJM contends, among other things, there remains significant uncertainty as to when the Ohio Commission will issue a final order to establish the appropriate FRR capacity price applicable to competitive retail electric service ("CRES") providers and that the Ohio Commission's actions to date are in conflict with section Schedule 8.1, Section D.8 of the RAA.[1] PJM further contends, there remains significant uncertainty as to when the Ohio Commission will issue a final order to establish the appropriate FRR capacity price applicable to CRES providers in the State of Ohio.

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[1] Schedule 8.1 reads as follows:

> In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

Contrary to PJM's concerns about uncertainty, the Ohio Commission has established an aggressive hearing schedule to resolve the AEP-Ohio CRES capacity issue since AEP-Ohio's Standard Service Offer (SSO) plan has been disapproved,[2] and the Ohio Commission is committed to aggressively resolving once and for all the issue of AEP's capacity charges to CRES providers. On March 14, 2012, the PUCO issued an entry in Docket No. 10-2929-EL-UNC[3] establishing an abbreviated hearing schedule timeline, which establishes a hearing date beginning on April 17, 2012. Moreover, in this same proceeding, in an attempt to ensure marketplace stability during the pendency of this matter, the Ohio Commission granted, with exceptions, AEP-Ohio's motion for interim relief to maintain the status quo approved in its disapproved stipulation to continue to use a two-tier pricing mechanism for CRES capacity pricing. Tier-one customers are entitled to pricing set by PJM's Reliability Pricing Model (RPM) capacity auction. The second tier charge for capacity is set equal to $255.00/MW-day. The interim relief was granted until May 31, 2012, when the state compensation mechanism shall revert to its previously Ohio Commission-approved level, which was set equal to the

2 In the Matter of the Application of Columbus Southern Power Company and Ohio Power Company for Authority to Establish a Standard Service Offer Pursuant to §4928.143, Ohio Rev. Code, in the Form of an Electric Security Plan, PUC Case Nos. 11-346-EL-SSO, et al., and In the Matter of the Application of the Columbus Southern Power Company and Ohio Power Company for Approval of Certain Accounting Authority, PUCO Case Nos. 11-349-EL AAM, et al.

3 In the Matter of the Commission Review of the Capacity Charges of Ohio Power Company and Columbus Southern Power Company, Case No. 10-2929-EL-UNC (Entry) (March 14, 2012).

then-current RPM capacity charges,[4] and will be the current RPM set pursuant to the PJM base residual auction for the 2012/2013 delivery years.

It is evident that the Ohio Commission is endeavoring to arrive at a CRES capacity rate that will promote alternative competitive supply and retail competition while simultaneously ensuring an incumbent electric utility provider's ability to attract capital investment to meet its FRR obligations. Arriving at this delicate balance is not a perfunctory endeavor. Contrary to PJM's allegations, which intimate that that the state determined capacity charge shall be set pursuant to cost,[5] none of the Ohio Commission's actions regarding these matters have been inconsistent with the RAA FRR tariff provisions.Indeed, the Ohio Commission is unaware as to where in the PJM RAA FRR tariff a state established cost based requirement is set forth.

PJM should not have amended the interpretation of its own tariff by suggesting that FERC interject itself into this intrastate ratemaking matter. Contrary to its current position, the Ohio Commission observes that PJM's previous comments in this proceeding affirmed a state's ability to establish an FRR capacity charge to CRES providers. Specifically, "PJM urged the Commission to deny the complaint and allow its members to rely on the RAA (state compensation mechanism) to set capacity costs for switching." PJM further stated that "[i]f AEP is concerned that the Ohio Commission somehow improperly took action beyond its jurisdiction, it should seek relief from state

4 The 2011/2012 rate, which became effective on June 1, 2011, is equal to $110.00 per MW-day not including adders for transmission losses the scaling factor).

5 Docket Nos. ER11-2183 and EL11-32 (PJM Response at 2, ¶ 2) (March 15, 2012).

or federal courts. The Commission has no power to reverse a state action."[6] PJM's previous position is correct. Consequently, FERC must discount PJM's Response as an incorrect intrusion into the state retail ratemaking process.

Finally, PJM's Response indicates that it is generally concerned about the effect prolonged regulatory uncertainty may have on PJM's markets. PJM further contends that uncertainty as to capacity prices could chill investment in new generation, which could impact reliability.[7] PJM's Response falls short of proposing any comprehensive resolution to address its concerns regarding potential adverse market impact and lack of capital investment. Indeed, the Ohio Commission maintains that PJM, as a neutral entity representing its diverse membership, should not have injected itself into this state retail ratemaking process. Contrary to PJM's allegations, as mentioned earlier, the Ohio Commission is endeavoring to arrive at a CRES capacity pricing mechanism that will incent customer choice while simultaneously safeguarding the necessary access to capital by the incumbent electric utility to ensure reliability. Moreover, the Ohio Commission is striving to safeguard an orderly transition for AEP-Ohio into the competitive marketplace. The Ohio Commission's dedication to this endeavor is shown by its aggressive hearing schedule for its Case No. 10-2929 investigation. Last, the Ohio Commission observes that many of its intrastate investigations and electric utility applications, upon which the PUCO must act, are often inextricably intertwined. FERC

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6 Docket No. EL11-32-000 (Answer of PJM Interconnection, L.L.C., to Complaint of American Electric Power Service Corporation) (April 25, 2011).

7 Docket Nos. ER11-2183 and EL11-32 (PJM Response at 3, ¶ 1) (March 15, 2012).

must be mindful of the deleterious impact any decision made at the federal level regarding these matters may have on the intrastate jurisdiction and the state of Ohio's consumers.

CONCLUSION

PJM should not have injected itself into this intrastate retail ratemaking process. The Ohio Commission has the resources to arrive at a reasonable CRES capacity charge that will promote competition while proving the electric utility access to the necessary capital to ensure reliability. For these reasons FERC must discount PJM's Response to AEP's Motion for Expedited Ruling. The Ohio Commission thanks FERC for the opportunity to provide its Answer in this proceeding.

Respectfully submitted,

/s/ Thomas W. McNamee

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On behalf of
The Public Utilities Commission of Ohio

CERTIFICATE OF SERVICE

I hereby certify that the foregoing have been served in accordance with 18 C.F.R. Sec. 385.2010 upon each person designated on the official service list compiled by the Secretary in this proceeding.

/s/ Thomas W. McNamee

Thomas W. McNamee

Dated at Columbus, Ohio this March 22, 2012.

COMPOSITE

EXHIBIT

104

FES

PENGAD 800-631-6989

INTERCONNECTION AGREEMENT

BETWEEN

APPALACHIAN POWER COMPANY

KENTUCKY POWER COMPANY

OHIO POWER COMPANY

COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY *

INDIANA & MICHIGAN ELECTRIC COMPANY

AND WITH

AMERICAN ELECTRIC POWER SERVICE CORPORATION,

AS AGENT

Dated: July 6, 1951, as modified and supplemented by:

Modification No. 1, August 1, 1951
Modification No. 2, September 20, 1962
Modification No. 3, April 1, 1975
Supplement No. 1 to
Modification No. 3, August 1, 1979
Supplement No. 2 to
Modification No. 3, August 27, 1979
Modification No. 4, November 1, 1980 *
Compliance Filing (FERC ordered), Opinion 266,
Docket Nos. ER84-579-006 and EL86-10-001

* Pursuant to Modification No. 4 the terms "Member" and "Members", whenever said terms appear in the 1951 Agreement, shall, on and after the time when Modification No. 4 shall become effective, include Columbus Company.

CONTENTS

0.1 THIS AGREEMENT, made and entered into as of the 6th day of July, 1951 by and between APPALACHIAN POWER COMPANY (Appalachian Company), a Virginia corporation, KENTUCKY POWER COMPANY (Kentucky Company), a Kentucky corporation, OHIO POWER COMPANY (Ohio Company), an Ohio corporation, COLUMBUS AND SOUTHERN OHIO ELECTRIC COMPANY (Columbus Company), an Ohio corporation, INDIANA & MICHIGAN ELECTRIC COMPANY (Indiana Company), an Indiana corporation, said companies (herein sometimes called 'Members' when referred to collectively and 'Member' when referred to individually), being affiliated companies of an integrated public utility electric system, and AMERICAN ELECTRIC POWER SERVICE CORPORATION (Agent), a New York corporation, being a service company engaged solely in the business of furnishing essential services to the aforesaid companies and to other affiliated electric utility companies.

The term "affiliate" shall include American Electric Power Company, Inc., Appalachian Power Company, Columbus and Southern Ohio Electric Company, Indiana & Michigan Electric Company, Kentucky Power Company, Ohio Power Company, Kingsport Power Company, Michigan Power Company, Wheeling Electric Company, and any subsidiaries, direct or indirect, of the foregoing.

W I T N E S S E T H,

T H A T:

0.2 WHEREAS, the Members own and operate electric facilities in the states herein indicated: (i) Appalachian Company in Tennessee, Virginia, and West Virginia, (ii) Kentucky Company in Kentucky, (iii) Ohio Company in Ohio and West Virginia, and (iv) Indiana Company in Indiana and Michigan, and (v) Columbus Company in Ohio, and

0.3 WHEREAS, the Members' electric facilities are now and have been for many years interconnected through their respective transmission facilities at a number of points (hereby designated and hereinafter called "Interconnection Points"), such facilities and the transmission facilities of other affiliated electric utility companies forming an integrated transmission network; and

0.4 WHEREAS, the transmission facilities of each Member are interconnected at a number of points with the transmission facilities of various non-affiliated electric utility companies, and those of Appalachian Company are interconnected with those of Tennessee Valley Authority, (said companies and Tennessee Valley Authority hereinafter sometimes called "Foreign Companies" when referred to collectively and "Foreign Company" when referred to individually; and

0.5 WHEREAS, the Members through cooperation with each other have been successful for some years in achieving substantial economies in the conduct of their business by coordinating the expansion and operation of their power supply facilities; and

0.6 WHEREAS, the Members believe that a fuller realization of the benefits and advantages through coordinated operation of their electric supply facilities will be better assured and more efficiently and economically achieved by having such operation directed and supervised by a centrally located organization skilled in the technique of system operation on a large scale and thoroughly familiar with the power supply facilities of the Members, and that their participation in the coordinated expansion and operation of their facilities will be simplified and facilitated by having such procedures conducted by a single clearing agent; and

0.7 WHEREAS, the Members believe that the Agent designated herein for such purpose is qualified to perform such services for them.

0.8 NOW, THEREFORE, in consideration of the premises and of the mutual covenants and agreements hereinafter contained, the parties hereto agree as follows:

ARTICLE I

PROVISIONS FOR, AND CONTINUITY OF INTERCONNECTED OPERATION

1.1 Throughout the duration of this agreement the systems of the Members shall be operated in continuous synchronism through each of the various lines interconnecting their respective systems; provided, however, if synchronous operation of the systems through a particular line or lines becomes interrupted because of reasons beyond the control of any Member or because of scheduled maintenance that has been agreed to by the Members, the Members shall cooperate so as to remove the cause of such interruption as soon as practicable and restore the affected line or lines to normal operating condition.

1.2 Each Member shall keep the portions of the lines interconnecting their respective systems, together with all associated facilities and appurtenances, that are located on their respective sides of the Interconnection Points in a sutiable condition of repair at all times in order that said lines will operate in a reliable and satisfactory manner and that reduction in their capacity will be avoided.

ARTICLE 2

OPERATING COMMITTEE

2.1 The parties herein shall appoint representatives to act as the "Operating Committee" in cooperation with each other and the Agent in the coordination and operation and/or use of the electric power sources of or available to the Members and of their transmission and distribution and substation facilities to the end that the advantages to be derived thereunder may be realized to the fullest practicable extent.

2.2 Each Member shall designate in writing delivered to the other Members and Agent, the person who is to act as its representative on said committee and the person or persons who may serve as alternate whenever such representative is unable to act. Agent shall designate in writing delivered to the Members the person who is to act as its representative on said committee. Such person shall act as chairman of the Operating Committee and shall be known as the "Pool Manager". All such representatives or alternates so designated shall be fully authorized to cooperate with the other representatives or alternates in all matters described in this agreement as responsibilities of the Operating Committee.

ARTICLE 3

AGENT'S RESPONSIBILITIES

3.1 For the purpose of carrying out the coordinated operation of the generating and transmission facilities of Members and the most efficient use of the energy produced by them and of other energy available to them, the Members hereby delegate to Agent and Agent hereby accepts the responsibility of supervising and directing such operation and use, and in furtherance thereof Agent agrees as follows; viz:

3.11 To coordinate the operation of the electric power sources of or available to the Members, which include their own generating stations and electric power available to them through interconnection with affiliated companies other than Members and Foreign Companies.

3.12 To arrange for and conduct such meetings of the Operating Committee as may be required to insure the effective and efficient carrying out of all matters of procedure essential to the complete performance of the provisions of this agreement.

3.13 To prepare and collect such log sheets and other records as may be needed to afford a clear history of the electric power and energy supplied under this agreement. Preparation and collection of such log sheets and other record shall be coordinated with similar responsibilities of the Members as provided for under Article 9.

3.14 To render to each Member as promptly as possible after the end of each calendar month a statement setting forth the electric power and energy transactions carried out during such month pursuant to the provisions of this agreement in such detail and with such segregations as may be needed for operating records or for settlements hereunder.

3.15 To make arrangements with Foreign Companies on behalf of the Members for the purchase, sale, or interchange of power and energy between such companies and the Members, such arrangements to be made in addition to similar arrangements to be made under agreements between an individual Member and a Foreign Company and to be made whenever in the judgment of the Members the effecting of matters of operation and contract related thereto can be simplified and their performance facilitated.

3.16 To carry out cash settlements for electric power and energy supplied under this agreement. Settlements by the Members shall be made for each calendar month through an account (hereby designated and hereinafter called "SYSTEM ACCOUNT") to be administered by Agent. Payments to or from such account shall be made to or by Agent as clearing agent of the account. The total of the payments made by Members to the SYSTEM ACCOUNT for a particular month shall be equal to the payments made to the Members from the SYSTEM ACCOUNT for such month.

ARTICLE 4

MEMBERS' OBLIGATIONS AND RIGHTS

4.1 For the purpose of obtaining the most efficient coordinated expansion and operation of their electric power supply facilities the Members hereby agree to operate and utilize their electric power sources under the direction of the Pool Manager in such manner that each Member shall receive at all times sufficient electric power and energy from such sources to meet its specific load obligations.

Each member shall, to the extent practicable, install or have available to it under contract such capacity as is necessary to supply all of the requirements of its own customers.

4.2 The Members agree that their electric power sources, which shall include all the generating stations owned by the Members and all electric power available to them through interconnection with affiliated companies other than Members and Foreign Companies, shall be used as needed to carry the combined load obligations of the Member under the direction of the Pool Manager. Each Member in return shall receive at all times sufficient electric power and energy from such sources to meet the specific load obligations of such Member.

4.3 The Members recognize that in carrying out the interconnected operation of their respective transmission systems as herein provided, electric energy being received by a portion of a particular Member's transmission system from another portion of such system or from the system of another interconnected company, or electric energy being delivered by a portion of a particular Member's transmission system to another portion of such system or to the system of another interconnected company, may flow over the transmission system of another Member. In respect of such flow of electric energy (hereinafter called "Energy Transfer") the Members agree that such Energy Transfer over their respective transmission facilities shall be permitted whenever it occurs, and, except as may be specifically agreed to otherwise by the Members, no Member shall make a charge at any time to another Member to permit such Energy Transfer. Electric power and energy associated with such Energy Transfer, including electrical losses associated therewith, shall be accounted for each clockhour. Proper consideration shall be given to such electrical losses in accordance with the manner determined and agreed upon by the Operating Committee, and such consideration shall be fully in accord with the provisions of LINE LOSS FACTOR as defined under subdivision 5.15 of Article 5.

ARTICLE 5

DEFINITIONS OF LOAD, CAPACITY, AND ENERGY CLASSES
AND RELATED FACTORS ASSOCIATED WITH SETTLEMENTS
FOR POWER SUPPLIED FROM MEMBER'S ELECTRIC POWER SOURCES

5.1 Load, capacity, and energy shall be designated and allocated to various classes for the purposes of effecting settlements under this agreement. Load, capacity, and energy classes and related factors associated with the settlement for electric power and energy supplied from electric power sources of the Members are defined as follows: viz:

Load

5.2 MEMBER LOAD OBLIGATION - A Member's internal load plus any firm power sales to Foreign Companies and to affiliated companies other than Members. Principally characterized by the Member assuming the load obligation as its own firm power commitment and by the Member retaining advantages accruing from meeting the load.

5.3 SYSTEM LOAD OBLIGATION - Load obligation shared proportionately by the Members where one Member or Agent will act as Agent of the Members in meeting the commitment; principally characterized by the load not being considered as a part of any MEMBER LOAD OBLIGATION.

(Examples of SYSTEM LOAD OBLIGATIONS are electric power and energy deliveries made to Foreign Companies under emergency and storage power arrangements with such companies.)

5.4 MEMBER DEMAND - MEMBER LOAD OBLIGATION determined on a clock-hour integrated kilowatt basis.

5.5 MEMBER MAXIMUM DEMAND - The MEMBER MAXIMUM DEMAND in effect for a calendar month for a particular Member shall be equal to the maximum MEMBER DEMAND experienced by said Member during the twelve consecutive calendar months next preceding such calendar month.

5.6 MEMBER LOAD RATIO - The ratio of a particular Member's MEMBER MAXIMUM DEMAND in effect for a calendar month to the sum of the five MEMBER MAXIMUM DEMANDS in effect for such month.

Capacity

5.7 MEMBER PRIMARY CAPACITY - The aggregate capacity of the electric power sources of a particular Member, in Kilowatts, that is normally expected to be available to carry load. Such capacity shall include (i) the capacity installed at the generating stations owned by the Member and (ii) the capacity available to that Member through interconnection arrangements with affiliated companies or Foreign Companies, if so designated by the Operating Committee with the approval of the Members.

5.7.1 All determinations by the Operating Committee pursuant to (ii) of Section 5.7 with respect to purchases of capacity from non-affiliated companies shall take into account, but shall not be limited to, the following circumstances and considerations: (1) the term during which such capacity will be available, a commitment from a reliable source of power and energy for at least five years being normally regarded as appropriate for inclusion as a capacity source of a particular Member, with purchases of a short or intermediate duration being normally regarded as System purchases under Article 7; (2) whether the availability of the purchased capacity will be comparable to the availability of the installed primary capacity of the Members, although the Operating Committee may make adjustments in the quantity of purchased capacity to be included as Member Primary Capacity to give effect to any disparity in the availability of such purchased capacity; (3) the need on the part of a Member with a Member Primary Capacity deficit of an extended nature to rectify or alleviate such deficit and the interest of all Members in maintaining an equalization among the Members of capacity resources over a period of time.

5.7.2 In the event that arrangements are made hereunder for any Member to make capacity available to an affiliated company or to a Foreign Company through the sale by such Member, for its own account, of unit capacity or other non-firm capacity, the amount of the capacity so sold shall be excluded from the Primary Capacity of such Member.

5.8 SYSTEM PRIMARY CAPACITY - The sum of the MEMBER PRIMARY CAPACITY of all the Members.

5.9 MEMBER PRIMARY CAPACITY RESERVATION - SYSTEM PRIMARY CAPACITY multiplied by the MEMBER LOAD RATIO of a particular Member.

5.10 MEMBER PRIMARY CAPACITY SURPLUS - Difference between the MEMBER PRIMARY CAPACITY and MEMBER PRIMARY CAPACITY RESERVATION of a particular Member, when such MEMBER PRIMARY CAPACITY exceeds such MEMBER PRIMARY CAPACITY RESERVATION.

5.11 MEMBER PRIMARY CAPACITY DEFICIT - Difference between the MEMBER PRIMARY CAPACITY and MEMBER PRIMARY CAPACITY RESERVATION of a particular Member, when such MEMBER PRIMARY CAPACITY is less than such MEMBER PRIMARY CAPACITY RESERVATION.

<u>Energy</u>

5.12 POOL - Electric energy delivered by one Member, from its MEMBER PRIMARY CAPACITY, to another Member shall be considered to be energy delivered to the POOL by the former Member and received from the POOL by the latter Member.

Electric energy delivered by a Foreign Company to a Member, other than energy associated with a Member's MEMBER PRIMARY CAPACITY, shall be considered to be energy delivered to the POOL. Electric energy delivered by a Member to a Foreign Company to meet a SYSTEM LOAD OBLIGATION shall be considered to be energy delivered by the POOL to the Foreign Company.

5.13 PRIMARY ENERGY - Electric energy delivered to the POOL from the MEMBER PRIMARY CAPACITY of a particular Member to meet another Member's deficiency in capacity. The deficiency may be caused by one or both of two reasons, the total MEMBER PRIMARY CAPACITY of a particular Member may not be great enough to meet its MEMBER LOAD OBLIGATION or a Member may have a portion of its MEMBER PRIMARY CAPACITY out of service for maintenance and the remainder may not be great enough to meet its MEMBER LOAD OBLIGATION.

5.14 ECONOMY ENERGY - Electric energy delivered to the POOL from the MEMBER RRIMARY CAPACITY of a particular Member to displace energy that otherwise would be supplied by less efficient MEMBER PRIMARY CAPACITY of another Member to meet its MEMBER LOAD OBLIGATION.

5.15 LINE LOSS FACTOR - The transmission electrical loss factor to be applied for settlement purposes to a particular metered quantity of energy delivered to the POOL by a Member. The Operating Committee shall determine and agree upon the LINE LOSS FACTOR required, such determinations to be governed by the understanding that the Member receiving such energy shall bear the entire loss caused in transmitting such energy over the facilities of the delivering Member and over the facilities of any other party whose system may be used for such delivery.

ARTICLE 6

SETTLEMENTS FOR POWER AND ENERGY
SUPPLIED FROM MEMBER'S ELECTRIC POWER SOURCES

6.1 As promptly as practicable following the end of each month (all references to month mean calendar month), for electric power and energy supplied under this agreement during such month from SYSTEM PRIMARY CAPACITY, the Members shall carry out cash settlements through the SYSTEM ACCOUNT in accordance with the following; viz:

Primary Capacity Equalization Charge

6.2 For each kilowatt of MEMBER PRIMARY CAPACITY SURPLUS each Member having such surplus during any month shall receive payment from the SYSTEM ACCOUNT at a rate per kilowatt per month equal to the MEMBER PRIMARY CAPACITY INVESTMENT RATE plus the MEMBER PRIMARY CAPACITY FIXED OPERATING RATE, as hereinbelow defined, applicable to the particular surplus.

6.21 The MEMBER PRIMARY CAPACITY INVESTMENT RATE chargeable against the SYSTEM ACCOUNT for any calendar month by a particular Member shall be equal to the product of (A) the MEMBER WEIGHTED AVERAGE INVESTMENT COST, determined pursuant to subdivision 6.211 below, and (B) the MONTHLY CARRYING CHARGE FACTOR, determined pursuant to subdivision 6.212 below.

6.211 The MEMBER WEIGHTED AVERAGE INVESTMENT COST shall be equal to the ratio of (i) the total installed cost of production plant of the generation stations, other than hydro, classified as part of a particular Member's MEMBER PRIMARY CAPACITY to (ii) the total kilowatt capability of such generating stations. The total installed cost of production plant used in the determination of the MEMBER WEIGHTED AVERAGE INVESTMENT COST, as described above, shall be the total cost of such plant for the aforesaid generating stations included, as of the end of the next preceding year, in Accounts 310 to 316, inclusive, Accounts 320 to 325, inclusive and Accounts 340 to 346, inclusive, of the Uniform System of Accounts prescribed by the Federal Energy Regulatory Commission for Public Utilities and Licensees, as in effect on January 1, 1975.

6.212 The MONTHLY CARRYING CHARGE FACTOR shall be 0.0137, or such larger amount as shall be established by order of the Federal Energy Regulatory Commission issued upon rehearing or reconsideration of its Opinion No. 50, issued July 27, 1979 in Docket No. E-9408.

6.22 The MEMBER PRIMARY CAPACITY FIXED OPERATING RATE chargeable against the SYSTEM ACCOUNT for any calendar month by a particular Member shall be equal to the weighted average fixed operating cost as hereinbelow defined, incurred by said Member during such month. Such weighted average fixed operating cost for purposes hereof shall be equal to the ratio of the fixed operating expense, i.e., the total production expenses minus the fuel and one-half of the maintenance expenses, incurred by a particular Member during a month at the generating stations other than hydro, classified as a part of its MEMBER PRIMARY CAPACITY to the total kilowatt capability of such generating stations.

6.3 For each kilowatt of MEMBER PRIMARY CAPACITY DEFICIT, any Member having such deficit during any month shall make payment into the SYSTEM ACCOUNT at a rate per kilowatt per month equal to the total payments from the SYSTEM ACCOUNT during any such month, determined pursuant to subdivision 6.2 above, divided by the total kilowatts of MEMBER PRIMARY CAPACITY DEFICITS for such month.

Primary Energy Charge

6.4 For PRIMARY ENERGY delivered to the POOL during any month by any Member, the Member so delivering such energy shall receive payment from the SYSTEM ACCOUNT at a rate per kilowatt-hour equal to said Member's MEMBER PRIMARY ENERGY RATE, as hereinbelow defined, for such month. The MEMBER PRIMARY ENERGY RATE chargeable against the SYSTEM ACCOUNT for any month by said Member shall be equal to the Member's weighted average variable production cost, as hereinbelow defined, for such month. Such weighted average variable production cost for purposes hereof shall be equal to the ratio of the sum of the fuel and one-half of the maintenance expenses incurred by said Member during a month at the generating stations other than hydro, classified as part of such Member's MEMBER PRIMARY CAPACITY to the total kilowatt-hours of net generation at said generating stations during such month.

6.5 For PRIMARY ENERGY received from the POOL during any month by any Member, said Member shall make payment into the SYSTEM ACCOUNT for energy so received at a rate per kilowatt-hour equal to the MEMBER PRIMARY ENERGY RATE payable from the SYSTEM ACCOUNT to the other Members for such month for such PRIMARY ENERGY. THe rate applicable to such PRIMARY ENERGY shall be determined from clock-hour records to be kept by Agent as provided under Article 3. Such records shall indicate the receiving Member and supplying Member for each kilowatt-hour classified as PRIMARY ENERGY.

Economy Energy Charge

6.6 For ECONOMY ENERGY delivered to the POOL during any month the Member delivering such energy shall receive payment from and the Member receiving such energy shall make payment to the SYSTEM ACCOUNT at the ECONOMY ENERGY RATE, as hereinbelow defined, applicable to the energy so delivered and received. The ECONOMY ENERGY RATE applicable to a particular kilowatt-hour of ECONOMY ENERGY shall be equal to the out-of-pocket cost of delivering said kilowatt-hour to the POOL plus one-half the difference between such cost and the out-of-pocket cost of generation avoided by the Member receiving such energy. Said kilowatt-hour shall be considered to be supplied from the highest cost source carrying load to meet MEMBER LOAD OBLIGATIONS of the supplying Member, excluding sources operated for minimum operating requirements, and its out-of-pocket cost shall include fuel expense and an appropriate portion of maintenance expense of generating facilities. The cost of generation avoided by the Member receiving said kilowatt-hour of ECONOMY ENERGY shall be considered to be the out-of-pocket cost that would be experienced if said kilowatt-hour were not delivered and its equivalent generated upon the most efficient operable unloaded generation of the receiving Member. Such out-of-pocket cost shall include cost of fuel and an appropriate portion of maintenance expense of generating facilities. The appropriate portion of maintenance expense allocable to the out-of-pocket cost of the supplying Member and to the avoided cost of the receiving Member shall be determined and agreed upon by the Operating Committee.

<u>System Primary Energy Rate</u>

6.7 Settlements for various classes of electric power and energy delivered under transactions with Foreign Companies shall include the use of a rate referred to as SYSTEM PRIMARY ENERGY RATE. For purposes of this agreement, the SYSTEM PRIMARY ENERGY RATE chargeable for any month shall be equal to the weighted average variable operating cost, as hereinbelow defined, incurred during such month at the generating stations, other than hydro, classified as part of the SYSTEM PRIMARY CAPACITY. Such weighted average variable operating cost for purposes hereof shall be equal to the ratio of the variable production expenses, i.e., the fuel and one-half of the maintenance expenses, incurred during a month at the generating stations, other than hydro, classified as part of the SYSTEM PRIMARY CAPACITY to the total kilowatt-hours of net generation generated at said generating stations during such month.

ARTICLE 7

TRANSACTIONS WITH FOREIGN COMPANIES

7.1 As promptly as practicable following the end of each month, cash settlements by the Members through the SYSTEM ACCOUNT for power transactions carried out in their behalf with Foreign Companies during such month shall be effected in accordance with the principles and procedures provided therefor under this Article 7. Any sale of power included in a Member's MEMBER LOAD OBLIGATION and any purchase of power included in a Member's MEMBER PRIMARY CAPACITY shall be excluded from such transactions. All other types of transactions carried out by any Member or on behalf of the Members with any Foreign Company shall be considered a transaction made on behalf of the collective interest of the Members. Costs and benefits associated with such transactions shall be shared proportionately as hereinbelow provided.

Settlement For Power And Energy
Purchases From Foreign Companies

Power and Energy Purchases
other than Economy Energy

7.2 Definitions of billing factors required for settlements by the Members through the SYSTEM ACCOUNT for electric power and energy, other than ECONOMY ENERGY PURCHASE from any Foreign Company shall be as follows; viz:

7.21 SYSTEM PURCHASE FROM FOREIGN COMPANY - All energy purchased from a Foreign Company either by a particular Member or by the Members collectively through arrangements made on their behalf by Agent, except ECONOMY ENERGY or such energy as may be purchased to meet a SYSTEM LOAD OBLIGATION (settlement for energy so purchased that is supplied to another Foreign Company is provided for under subdivisions 7.5 and 7.7 below.)

7.22 MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, the SYSTEM PURCHASE FROM FOREIGN COMPANY multiplied by the MEMBER LOAD RATIO of a particular Member.

7.23 MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds such quantity of energy delivered to said Member by the Foreign Company, the difference between such quantities is the MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.24 MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member is less than such quantity of energy delivered to said Member by the Foreign Company, the difference between such quantities is the MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.25 MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER OBLIGATION OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM PURCHASE from FOREIGN COMPANY delivered to the POOL by the Member, the difference between such quantities is the MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.26 MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER ENTITLEMENT OF SYSTEM PURCHASE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM PURCHASE FROM FOREIGN COMPANY received from the POOL by said Member, the difference between such quantities is the MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY of said Member for such month.

7.3 To effect a proportionate sharing of the cost of any SYSTEM PURCHASE FROM FOREIGN COMPANY, purchases so made from each Foreign Company shall be treated separately as follows:

7.31 At the end of each month, from data supplied by the Members, Agent shall determine the cost of SYSTEM PURCHASE FROM FOREIGN COMPANY.

7.32 The total cost so determined multiplied by the [MEMBER] LOAD RATIO of a particular Member shall be the gross amount chargeable to said Member.

7.33 If a particular Member has established a MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY, the adjusted gross amount chargeable to the Member shall equal the sum of the gross amount determined under subdivision 7.32 above plus the amount chargeable to the Member for the MEMBER DEFICIT OF SYSTEM PURCHASE FROM FOREIGN COMPANY. The rate applicable to such deficit shall be the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.34 If a particular Member has established a MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY, the adjusted gross amount chargeable to the Member shall equal the difference between the gross amount determined under subdivision 7.32 above and the amount to be credited to the Member for the MEMBER SURPLUS OF SYSTEM PURCHASE FROM FOREIGN COMPANY. The rate applicable to such surplus shall be the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.35 If the adjusted gross amount chargeable to a particular Member for any month as determined under either subdivisions 7.33 or 7.34 is greater than the payment make by said Member to the Foreign Company for the SYSTEM

PURCHASE FROM FOREIGN COMPANY, said Member shall make payment into the SYSTEM ACCOUNT of the difference between such amount and payment. Conversely, if the amount so determined for a particular Member is less than the Member's aforesaid payment to the Foreign Company, such Member shall receive payment from the SYSTEM ACCOUNT of the difference between such amount and such payment to the Foreign Company.

Economy Energy Purchases

7.4 Settlement by the Members through the SYSTEM ACCOUNT for ECONOMY ENERGY PURCHASE from a Foreign Company shall be governed by the principle that the saving in production expense realized by the System (the term "System" as used in this agreement refers to the electric facilities of the Members viewed as a unit) shall be shared by the Members in proportion to their respective MEMBER LOAD RATIOS.

(The following illustrates the application of the principle and procedure for effecting such settlements:

It is assumed that Appalachian Company has purchased a block of ECONOMY ENERGY PURCHASE at a rate of 1.00 mill per kilowatt-hour which has displaced generation at Twin Branch Station of Indiana Company; the production expense saving to Indiana Company being 2.00 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy shall be at the following rates: (1) pay Appalachian Company at a rate per kilowatt-hour equal to the sum of 1.00 mill plus the product of 2.00 mills times Appalachian Company's MEMBER LOAD RATIO, (2) pay Ohio Company at a rate per kilowatt-hour equal to the product of 2.00 mills times Ohio Company's MEMBER LOAD RATIO, and (3) charge Indiana Company at a rate per kilowatt-hour equal to the sum of 1.00 mill plus the product of 2.00 mills times the sum of Appalachian Company's and Ohio Company's MEMBER LOAD RATIOS.)

For the purpose of this agreement, the cost of generation avoided by the System in receiving a kilowatt-hour of ECONOMY ENERGY PURCHASE shall be considered to be the out-of-pocket cost, i.e., fuel expense and an appropriate portion of maintenance expense of generating facilities that would be experienced if said kilowatt-hour were not delivered and its equivalent generated upon the most efficient operable unloaded generation of the System. The appropriate portion of maintenance expense allocable to the out-of-pocket cost of such generating facilities shall be determined and agreed upon by the Operating Committee.

Settlement for Power Sales to Foreign Companies

7.5 Settlement by the Members through the SYSTEM ACCOUNT for electric power and energy sales to Foreign Companies shall be governed by the principle that the difference between the amount charged a Foreign Company for the power and energy supplied under such a sale and the production expenses, i.e., out-of-pocket costs incurred by the System in making such supply, shall be shared by the Members in proportion to the respective MEMBER LOAD RATIOS. Electric Power and energy for such sales shall be considered to be supplied from the higher cost of the following two sources: (1) from the highest cost source carrying load on the System, excluding sources operated for minimum operating requirements, or (2) the highest cost source supplying power to the System under arrangements with Foreign Companies.

(The following illustrates the application of the principles and procedures for effecting such settlements:

It is assumed that Indiana Company has sold a block of energy at a rate of 4.00 mills per kilowatt-hour which has been supplied by carrying a block of load that would not otherwise be carried at Philo Station of Ohio Company, the out-of-pocket cost incurred by Ohio Company being 3.00 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy would be at the following rates: (1) charge

Indiana Company at a rate per kilowatt-hour equal to the sum of 3.00 mills plus the product of 1.00 mill times the sum of Appalachian Company's and Ohio Company's MEMBER LOAD RATIOS, (2) pay Ohio company at a rate per kilowatt-hour equal to the sum of 3.00 mills and the product of 1.00 mill times Ohio Company's MEMBER LOAD RATIO, and (3) pay Appalachian Company at a rate per kilowatt-hour equal to the product of 1.00 mill times Appalachian Company's MEMBER LOAD RATIO.)

Settlement For Power and Energy Received Under <u>Interchange Arrangements With Foreign Companies</u>

Power and Energy Received other <u>than Interchange Economy Energy</u>

7.6 Definitions of billing factors required for settlements by the Members through the SYSTEM ACCOUNT for electric power and energy received, other than INTERCHANGE ECONOMY ENERGY, from any Foreign Company under interchange arrangements which require no cash settlements shall be as follows; viz:

7.61 SYSTEM INTERCHANGE FROM FOREIGN COMPANY - All energy received from Foreign Company by either a particular Member or by the Members collectively through arrangements made on their behalf by Agent, which requires no cash settlement, except INTERCHANGE ECONOMY ENERGY.

7.62 MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, the SYSTEM INTERCHANGE FROM FOREIGN COMPANY multiplied by the MEMBER LOAD RATIO of a particular Member.

7.63 MEMBER ENTITLEMENT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of such energy delivered to the Member by the Foreign Company, the difference between such quantities is the MEMBER ENTITLEMENT OF SYSTEM

INTERCHANGE FROM FOREIGN COMPANY of such Member for such month.

7.64 MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER RESERVATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member is less than the quantity of such energy delivered to the Member by the Foreign Company, the difference between such quantities is the MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.65 MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER OBLIGATION OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM INTERCHANGE FROM FOREIGN COMPANY delivered to the POOL by said Member, the difference between such quantities is the MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.66 MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY - For a month, when the quantity of the MEMBER ENTITLEMENT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY for a particular Member exceeds the quantity of kilowatt-hours of SYSTEM INTERCHANGE FROM FOREIGN COMPANY received from the POOL by said Member, the difference between such quantities is the MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY of said Member for such month.

7.7 To effect a proportionate sharing of the benefits of SYSTEM INTERCHANGE FROM FOREIGN COMPANY, electric energy so received from each Foreign Company shall be treated separately as follows:

7.71 If a particular Member has established a MEMBER DEFICIT OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY, said Member shall make payment into the SYSTEM ACCOUNT for the kilowatt-hours of such deficit at the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

7.72 If a particular Member has established a MEMBER SURPLUS OF SYSTEM INTERCHANGE FROM FOREIGN COMPANY, said Member shall receive payment from the SYSTEM ACCOUNT for the kilowatt-hours of such surplus at the SYSTEM PRIMARY ENERGY RATE determined for the particular month.

Interchange Economy Energy

7.8 The priciples described under subdivision 7.4 above for the settlement of ECONOMY ENERGY PURCHASE shall also govern the settlements by the Members through the SYSTEM ACCOUNT for INTERCHANGE ECONOMY ENERGY received from a Foreign Company. It shall be assumed for the purpose of such settlement that payment to the Foreign Company for INTERCHANGE ECONOMY ENERGY was made at a rate of zero mills per kilowatt-hour.

Settlements For Power Delivered Under Interchange Arrangements With Interconnected Foreign Companies

7.9 Settlement hereunder for electric power and energy (hereinafter called "SYSTEM INTERCHANGE TO FOREIGN COMPANY") delivered to any Foreign Company under interchange arrangements with either a particular Member or with the Members collectively through arrangements made on their behalf by Agent, which require no cash settlements, will be governed by the principle that the production expenses, i.e., out-of-pocket costs incurred by the System in making such deliveries, shall be shared by the

Members in proportion to their respective MEMBER LOAD RATIOS.

(The following illustrates the application of the principle and procedure for effecting such settlements:

It is assumed that Appalachian Company has delivered a block of SYSTEM INTERCHANGE TO FOREIGN COMPANY which has been supplied by carrying a block of load that would not otherwise be carried at Windsor Station of Ohio Company; the out-of-pocket cost incurred by Ohio Company being 3.50 mills per kilowatt-hour.

Charges payable to and credits payable from the SYSTEM ACCOUNT for such energy shall be at the following rates: (1) charge Appalachian Company and Indiana Company at rates per kilowatt-hour equal to the product of 3.50 mills per kilowatt-hour and their respective MEMBER LOAD RATIOS, and (2) pay Ohio Company at a rate equal to the sum of the rates charged Appalachian Company and Indiana.)

As described under subdivision 7.5 above, electric power and energy for sales to Foreign Companies shall be considered to be supplied from the higher cost of the following two sources: (1) from the highest cost source carrying load on the System, excluding sources operated for minimum operating requirements, or (2) the highest cost source supplying electric power and energy to the System under arrangements with Foreign Companies. Similarly, following the determination and designation of such source for the aforesaid sales, electric power and energy for SYSTEM INTERCHANGE TO FOREIGN COMPANY deliveries shall be considered to be supplied from the higher cost of the balance of said two sources.

ARTICLE 8

DELIVERY POINTS, METERING POINTS AND METERING

Delivery Points

8.1 All electric energy delivered under this agreement shall be of the character commonly known as three-phase sixty-cycle energy, and shall be delivered at the various Interconnection points where the transmission systems of the Members are interconnected at the nominal unregulated voltage designated for such points, and at such other points and voltages as may be determined and agreed upon by the Members.

Metering Points

8.2 Electric power and energy supplied and delivered by one Member to another Member shall be measured by suitable metering equipment to be provided, owned, and maintained by the Members at such metering points as are determined and agreed upon by them.

Metering

8.3 Suitable metering equipment at metering points as provided under subdivision 8.2 above shall include electric meters which shall give for each direction of flow the following quantities (1) an automatic record for each clock-hour of kilowatt-hours and (2) a continuous integrating record of the kilowatt-hours.

8.4 Measurements of electric energy for the purpose of effecting settlements under this agreement shall be made by standard types of electric meters, installed and maintained by the owner at the metering points as provided under subdivision 8.2 above. The timing devices of all meters having such devices shall be maintained in time synchronism as closely as practicable. The meters shall be sealed and the seals shall be broken only upon occasions when the meters are to be tested or adjusted. For the purpose of checking the records of the metering equipment installed by any Member as hereinabove provided, the other Members shall have the right to install check metering equipment at the aforesaid metering points. Metering equipment so installed by one Member on the premises of another Member shall be owned and maintained by the Member installing such equipment. Upon termination of this agreement the Member owning such metering equipment shall remove it from the premises of the other Member. Authorized representatives of any Member shall have access at all reasonable hours to the premises where the meters are located and to the records made by the meters.

8.5 The aforesaid metering equipment shall be tested by the owner at suitable intervals and its accuracy of registration maintained in accordance with good practice. On request of any Member, special tests shall be made at the expense of the Member requesting such special test.

8.6 If on any test of metering equipment, an inaccuracy shall be disclosed exceeding two percent, the account between the Members for service theretofore delivered shall be adjusted to correct for the inaccuracy disclosed over the shorter of the following two periods: (1) for the thirty-day period immediately preceding the day of the test or (2) for the period that such inaccuracy may be determined to have existed. Should the metering equipment as hereinabove provided for fail to register at any time, the electric power and energy delivered shall be determined from the check meters, if installed, or otherwise shall be determined from the best available data.

ARTICLE 9

RECORDS AND STATEMENTS

9.1 In addition to meter records to be kept by the Members as provided under Article 8, the Members shall keep in duplicate such log sheets and other records as may be needed to afford a clear history of the various deliveries of electric power and energy made pursuant to the provisions of this agreement. The originals of log sheets and other records shall be retained by the Member keeping the records and the duplicates shall be delivered as determined and agreed upon by the Operating Committee.

ARTICLE 10

TAXES

10.1 If at any time during the duration of this agreement, there should be levied and/or assessed against any Member any tax by any taxing authority in respect of the electric power and energy generated, purchased, sold, imported, transmitted, interchanged, or exchanged by said Member in addition to or different from the forms of such taxes now being levied or assessed against said Member, or there should be any increase or decrease in the rate of such existing or future taxes, and such taxes or changes in such taxes should result in increasing or decreasing the cost to said Member in carrying out the provisions of this agreement, then in such event adjustments shall be made in the rates and charges for electric power and energy furnished hereunder to make allowance for such taxes and changes in such taxes in an equitable manner.

ARTICLE 11

BILLINGS AND PAYMENTS

11.1 All bills for amounts owed hereunder shall be due and payable on the twentieth day of the month next following the monthly or other period to which such bills are applicable, or on the fifteenth day following receipt of bill, whichever date be later. Interest on unpaid amounts shall accrue at the rate of six percent per annum from the date due until the date upon which payment is made. Unless otherwise agreed upon a calendar month shall be the standard monthly period for the purpose of settlements under this agreement.

ARTICLE 12

MODIFICATION

12.1 Any Member, by written notice given to the other Members and Agent not less than ninety days prior to the beginning of any calendar year of the duration of this agreement, may call for a reconsideration of the terms and conditions herein provided. If such reconsideration is called for, there shall be taken into account any changed conditions, any results from the application of said terms and conditions, and any other factors that might cause said terms and conditions to result in an inequitable division of the benefits of interconnected operation or in an inadequate realization of such benefits. Any modification in terms and conditions agreed to by the Members following such reconsideration shall become effective the first day of January of the calendar year next following the aforesaid ninety-day notice period.

ARTICLE 13

DURATION OF AGREEMENT

13.1 This agreement shall become effective August 1, 1951, and shall continue in effect for an initial period expiring December 31, 1971, and thereafter for successive periods of one year each until terminated as provided under subdivision 13.2 below.

13.2 Any Member upon at least three years' prior written notice to the other Members and Agent may terminate this agreement at the expiration of said initial period or at the expiration of any successive period of one year.

ARTICLE 14

TERMINATION OF EXISTING AGREEMENTS

14.1 Upon their joint execution of this agreement Appalachian Company and Ohio Company agree that the interconnection agreements between them dated November 28, 1930, and September 1, 1936, respectively, and all supplements and amendments thereto, shall terminate as of July 31, 1951, and that all further obligations between them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.

14.2 Upon their joint execution of this agreement Indiana Company and Ohio Company agree that the interconnection agreements between them, dated October 15, 1930, and September 1, 1936, respectively, and all supplements and amendments thereto, shall terminate as of July 31, 1951, and that all further obligations between them in respect thereof shall cease and terminate as of such date, except in respect of any payments or liabilities incurred in respect thereof prior to such termination date.

ARTICLE 15

REGULATORY AUTHORITIES

15.1 This agreement is made subject to the jurisdiction of any governmental authority or authorities having lawful jurisdiction in the premises.

ARTICLE 16

ASSIGNMENT

16.1 This agreement shall inure to the benefit of and be binding upon the successors and assigns of the respective parties.

16.2 IN WITNESS WHEREOF, the parties hereto have caused this agreement to be executed in their respective corporate names and on their behalf by their proper officers thereunto duly authorized as of the day and year first above written.

(The numerous pages of the various signatories to the original Agreement and subsequent modifications thereto, are omitted herein.)

EXHIBIT
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FES

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY

INT-4-005. In Exhibit LJT-2, does the "2011 Base ESP 'g' rate" include both energy and capacity costs?

RESPONSE:

The Company objects to this request as seeking information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence Without waiving these objections or any general objection the Company may have, the Company states as follows.

SB221 does not require rates for generation service, including capacity and energy, to be based on cost AEP Ohio has not conducted a cost of service study for unbundled generation service. However, the 2011 Base ESP 'g' rate includes both energy and capacity.

Prepared By: Laura J. Thomas

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO FOURTH SET

INTERROGATORY NO. 4-15:

INT-4-015. In Exhibit LJT-2, does the "2011 Base ESP 'g' rate" include ancillary service charges that CSP and OPCo incur as members in PJM? If the answer is "yes," please Identify all supporting workpapers and analysis that documents all of the ancillary service charges that form the basis for the charges included in the "2011 Base ESP 'g' rate"

RESPONSE:

The Company objects to this request as seeking information that is neither relevant nor reasonably calculated to lead to the discovery of admissible evidence. Without waiving these objections or any general objection the Company may have, the Company states as follows.

SB221 does not require rates for generation service, including capacity and energy, to be based on cost AEP Ohio has not conducted a cost of service study for unbundled generation service. However, the 2011 Base ESP 'g' rate includes ancillary service charges.

See the Company's response to FES 4-009.

Prepared By: Laura J. Thomas

COLUMBUS SOUTHERN POWER COMPANY'S AND OHIO POWER COMPANY'S RESPONSE TO FIRSTENERGY SOLUTIONS DISCOVERY REQUEST CASE NO. 11-346-EL-SSO AND 11-348-EL-SSO TENTH SET

INTERROGATORY

INT-10-11 Please explain whether each of the following factors are credited against Your alleged capacity costs under the ESP:

a) Capacity sales under the AEP East agreement;
b) Energy sales under the AEP East agreement;
c) Other market sales of energy only to non-affiliates;
d) Other market sales of capacity only to non affiliates; and,
e) Combined capacity and energy sales to non-affiliates.

RESPONSE

See Companies' response to FES INT 10-05.

SUPPLEMENTAL RESPONSE

If "alleged" capacity costs is defined as the capacity costs contained in our current ESP or SSO rates, the Company's ESP is not cost based and the Company has not identified any specific capacity costs or capacity credits in its rates.

Prepared By: Philip J. Nelson/ Laura J. Thomas

EXHIBIT

PENGAD 800-631-6989

104

IEU Group

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of Each Exchange on Which Registered
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	None	
Indiana Michigan Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	New York Stock Exchange
Southwestern Electric Power Company	None	

Securities registered pursuant to Section 12(g) of the Act: None

capital. AEP expects to make substantial investments in future years in addition to the amounts set forth below in connection with the modification and addition of facilities at generating plants for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards that have been adopted and have deadlines for compliance after 2011 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more onerous or if CO_2 becomes regulated. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery those costs could adversely affect future results of operations and cash flows, and possibly financial condition. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. See Management's Financial Discussion and Analysis under the heading entitled Environmental Matters and Note 5 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, included in the 2011 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2009 Actual	2010 Actual	2011 Actual	2012 Estimate	2013 Estimate	2014 Estimate
			(in thousands)			
Total AEP System (a)	$ 457,200	$ 303,800	$ 186,800	$ 510,700	$ 999,000	$ 1,100,000
APCo	191,900	202,700	68,900	77,600	77,700	80,300
I&M	19,600	8,100	5,900	89,800	148,200	148,000
OPCo	224,800	97,400	63,000	122,800	187,300	128,700
PSO	1,000	1,200	6,500	43,400	134,600	164,600
SWEPCo (b)	10,700	(10,500)	11,000	75,700	230,500	288,100

(a) Includes expenditures of the subsidiaries shown and other subsidiaries not shown. The figures reflect construction expenditures, not equity investments in subsidiary companies. Excludes discontinued operations.

(b) SWEPCo 2010 actual environmental cost includes reclassifications of project costs for suspended capital projects.

Electric and Magnetic Fields

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring and appliances. A number of studies in the past have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from customers.

UTILITY OPERATIONS

GENERAL

Utility operations constitute most of AEP's business operations. Utility operations include (a) the generation, transmission and distribution of electric power to retail customers and (b) the supplying and marketing of electric power at wholesale (through the electric generation function) to other electric utility companies, municipalities and other market participants. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities.

In many jurisdictions, the rates of AEP's public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In the ERCOT area of Texas, our utilities have exited the generation business and they currently charge unbundled cost-based rates for transmission and distribution service only. In Ohio, rates for electric service are unbundled for generation, transmission and distribution service. Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes.

The following state-by-state analysis summarizes the regulatory environment of certain major jurisdictions in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction. See Note 3 to the consolidated financial statements, entitled Rate Matters, included in the 2011 Annual Reports, for more information regarding pending rate matters.

Indiana

I&M provides retail electric service in Indiana at bundled rates approved by the IURC, with rates set on a cost-of-service basis. Indiana provides for timely fuel and purchased power cost recovery through a fuel cost recovery mechanism.

Ohio

OPCo provides "default" retail electric service to customers at unbundled rates pursuant to the Ohio Act. OPCo exclusively provides distribution and transmission services to retail customers within their service territories at cost-based rates approved by the PUCO. Transmission services are provided at OATT rates based on rates established by the FERC. OPCo's generation/supply rates are subject to its ESP that the PUCO approved in March 2009. In December 2011, the PUCO approved a modified stipulation for a new ESP for the period January 2012 through May 2016 that includes a standard service offer (SSO) pricing for generation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation for a new ESP and ordered a return to the 2011 ESP rates until a new rate plan is approved.

Oklahoma

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above or below the amount included in base rates are recovered or refunded by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers in the year following when new annual factors are established.

Texas

Retail customers in TCC's and TNC's ERCOT service area of Texas are served through non-affiliated Retail Electric Providers (REPs). TCC and TNC provide transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Effective September 2009, competition in the SPP area of Texas has been delayed until certain steps defined by statute and by PUCT rule have been accomplished. As such, the PUCT continues to approve base and fuel rates for SWEPCo's Texas operations on a cost of service basis.

FERC

Under the FPA, the FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The FERC also regulates the sale of power for resale in interstate commerce by (a) approving contracts for wholesale sales to municipal and cooperative utilities and (b) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its balancing area of the SPP, AEP has market-rate authority from the FERC, under which much of its wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. The AEP East Companies are members of PJM. SWEPCo and PSO are members of SPP.

The FERC has jurisdiction over the issuances of securities of most of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC limited "backstop" transmission siting authority as well as increased utility merger oversight.

Competition

Under current Ohio legislation, electric generation is sold in a competitive market in Ohio, and our native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers are targeting retail customers by offering alternative generation service. A growing number of OPCo's commercial retail customers have switched to alternative generation providers while additional Ohio customers have provided notice of their intent to switch. Currently, there are no limitations on the obligation of OPCo to provide below cost capacity rate pricing to alternative suppliers to support customers switching in Ohio. These evolving market conditions will continue to impact OPCo's results of operations. A retail supply subsidiary operates as a competitive retail electric service provider in Ohio.

The public utility subsidiaries of AEP, like the electric industry generally, face competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEP's public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they generally maintain a favorable competitive position. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

CONSTRUCTION PROGRAM

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. AEP forecasts approximately $3.1 billion of construction expenditures for 2012, excluding equity AFUDC, capitalized interest and assets acquired under leases. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

Construction Expenditures

The following table shows construction expenditures (including environmental expenditures) during 2011, 2010 and 2009 and a current estimate of 2012 construction expenditures. Actual amounts for 2011, 2010 and 2009 and budgeted amounts for 2012 exclude equity AFUDC, capitalized interest and assets acquired under leases.

	2012 Estimate (b)	2011 Actual	2010 Actual	2009 Actual
		(in thousands)		
Total AEP System (a)	$ 3,064,700	$ 2,669,000	$ 2,345,000	$ 2,792,000
APCo	448,500	463,077	534,334	543,587
I&M	468,400	301,241	333,238	332,775
OPCo	569,400	460,125	512,637	720,300
PSO	204,100	140,326	194,896	175,122
SWEPCo (b)	475,400	551,163	420,485	596,581

(a) Includes expenditures of other subsidiaries not shown. The figure reflects construction expenditures, not equity investments in subsidiary companies.
(b) Excludes Sabine.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, federal income and other taxes and other factors affecting cash requirements may increase or decrease the estimated capital requirements for the System's construction program.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to our generating plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could have a material adverse effect on results of operations and the financial condition of AEP and other AEP System companies. For risks related to owning a nuclear generating unit, see Note 5 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies under the heading Nuclear Contingencies for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 5 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, incorporated by reference in Item 8.

EXHIBIT
PENGAD 800-631-6989
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

☒ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

☐ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _________ to_________

Commission File Number	Registrants; States of Incorporation; Address and Telephone Number	I.R.S. Employer Identification Nos.
1-3525	AMERICAN ELECTRIC POWER COMPANY, INC. (A New York Corporation)	13-4922640
1-3457	APPALACHIAN POWER COMPANY (A Virginia Corporation)	54-0124790
1-3570	INDIANA MICHIGAN POWER COMPANY (An Indiana Corporation)	35-0410455
1-6543	OHIO POWER COMPANY (An Ohio Corporation)	31-4271000
0-343	PUBLIC SERVICE COMPANY OF OKLAHOMA (An Oklahoma Corporation)	73-0410895
1-3146	SOUTHWESTERN ELECTRIC POWER COMPANY (A Delaware Corporation)	72-0323455
	1 Riverside Plaza, Columbus, Ohio 43215	
	Telephone (614) 716-1000	

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of Each Exchange on Which Registered
American Electric Power Company, Inc.	Common Stock, $6.50 par value	New York Stock Exchange
Appalachian Power Company	None	
Indiana Michigan Power Company	None	
Ohio Power Company	None	
Public Service Company of Oklahoma	6% Senior Notes, Series B, Due 2032	New York Stock Exchange
Southwestern Electric Power Company	None	

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrants American Electric Power Company, Inc., and Appalachian Power Company is each a well-known seasoned issuer, as defined in Rule 405 on the Securities Act.	Yes ☒	No ☐
Indicate by check mark if the registrants Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company, are well-known seasoned issuers, as defined in Rule 405 on the Securities Act.	Yes ☐	No ☒
Indicate by check mark if the registrants are not required to file reports pursuant to Section 13 or Section 15(d) of the Exchange Act.	Yes ☐	No ☒
Indicate by check mark whether the registrants (1) have filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrants were required to file such reports), and (2) have been subject to such filing requirements for the past 90 days.	Yes ☒	No ☐
Indicate by check mark whether American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Power Company have submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).	Yes ☒	No ☐
Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (229.405 of this chapter) is not contained herein and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.	☐	

Indicate by check mark whether American Electric Power Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See definitions of 'large accelerated filer', 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☒	Accelerated filer	☐
Non-accelerated filer	☐ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark whether Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company are large accelerated filers, accelerated filers, non-accelerated filers or smaller reporting companies. See definitions of 'large accelerated filer', 'accelerated filer' and 'smaller reporting company' in Rule 12b-2 of the Exchange Act. (Check One)

Large accelerated filer	☐	Accelerated filer	☐
Non-accelerated filer	☒ (Do not check if a smaller reporting company)	Smaller reporting company	☐

Indicate by check mark if the registrants are shell companies, as defined in Rule 12b-2 of the Exchange Act. Yes ☐ No ☒

Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company meet the conditions set forth in General Instruction I(1)(a) and (b) of Form 10-K and are therefore filing this Form 10-K with the reduced disclosure format specified in General Instruction I(2) to such Form 10-K.

	Aggregate Market Value of Voting and Non-Voting Common Equity Held by Non-Affiliates of the Registrants as of June 30, 2011, the Last Trading Date of the Registrants' Most Recently Completed Second Fiscal Quarter	Number of Shares of Common Stock Outstanding of the Registrants at December 31, 2011
American Electric Power Company, Inc.	$18,215,373,666	483,422,868 ($6.50 par value)
Appalachian Power Company	None	13,499,500 (no par value)
Indiana Michigan Power Company	None	1,400,000 (no par value)
Ohio Power Company	None	27,952,473 (no par value)
Public Service Company of Oklahoma	None	9,013,000 ($15 par value)
Southwestern Electric Power Company	None	7,536,640 ($18 par value)

Note On Market Value Of Common Equity Held By Non-Affiliates

American Electric Power Company, Inc. owns all of the common stock of Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (see Item 12 herein).

Documents Incorporated By Reference

Description	Part of Form 10-K into which Document is Incorporated
Portions of Annual Reports of the following companies for the fiscal year ended December 31, 2011: American Electric Power Company, Inc. Appalachian Power Company Indiana Michigan Power Company Ohio Power Company Public Service Company of Oklahoma Southwestern Electric Power Company	Part II
Portions of Proxy Statement of American Electric Power Company, Inc. for 2012 Annual Meeting of Shareholders.	Part III

This combined Form 10-K is separately filed by American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company. Information contained herein relating to any individual registrant is filed by such registrant on its own behalf. Except for American Electric Power Company, Inc., each registrant makes no representation as to information relating to the other registrants.

You can access financial and other information at AEP's website, including AEP's Principles of Business Conduct (which also serves as a code of ethics applicable to Item 10 of this Form 10-K), certain committee charters and Principles of Corporate Governance. The address is www.AEP.com. AEP makes available, free of charge on its website, copies of its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC.

TABLE OF CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
AECC	Arkansas Electric Cooperative Corporation, a nonaffiliated corporation.
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., a holding company.
AEP East companies	APCo, I&M, KPCo and OPCo.
AEP Power Pool	Members are APCo, I&M, KPCo and OPCo. The AEP Power Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP River Operations	AEP's inland river transportation subsidiary, AEP River Operations LLC, operating primarily on the Ohio, Illinois and lower Mississippi rivers.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AEP System or the System	The American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP Transco	AEP Transmission Company, LLC, a subsidiary of AEP, an intermediate holding company for seven wholly-owned transmission companies.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEP Utilities	AEP Utilities, Inc., a subsidiary of AEP, formerly, Central and South West Corporation.
AFUDC	Allowance for Funds Used During Construction.
ALJ	Administrative law judge.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
Buckeye	Buckeye Power, Inc., a nonaffiliated corporation.
CAA	Clean Air Act.
CAAA	Clean Air Act Amendments of 1990.
CCS	Carbon capture and storage technology.
CCPC	Conesville Coal Preparation Company, a subsidiary of OPCo.
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act of 1980.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, the AEP electric utility subsidiary that was merged with and into OPCo effective December 31, 2011.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
DOE	United States Department of Energy.
DP&L	The Dayton Power and Light Company, a nonaffiliated utility company.
Duke Ohio	Duke Energy Ohio, Inc.
EMF	Electric and Magnetic Fields.
EPACT	The Energy Policy Act of 2005.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETEC	East Texas Electric Cooperative.

Term	Meaning
ETT	Electric Transmission Texas, LLC, a joint venture established to construct, fund, own and operate electric transmission assets within ERCOT.
FERC	Federal Energy Regulatory Commission.
Federal EPA	United States Environmental Protection Agency.
FPA	Federal Power Act.
GHG	Greenhouse gases.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
IGCC	Integrated Gasification Combined Cycle.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IURC	Indiana Utility Regulatory Commission.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
Lawrenceburg Plant	A 1,146 MW gas-fired unit owned by AEGCo and located near Lawrenceburg, Indiana.
LLWPA	Low-Level Waste Policy Act of 1980.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
Moody's	Moody's Investors Service, Inc.
MW	Megawatt.
MWH	Megawatthour.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP's Nonutility Money Pool is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
NPC	National Power Cooperatives, Inc., a nonaffiliated corporation.
NRC	Nuclear Regulatory Commission.
NSR Consent Decree	The 2007 settlement with the Federal EPA, the United States Department of Justice, certain states and special interest groups that ended the litigation which had alleged that APCo, I&M and OPCo violated the new source review requirements of the CAA.
OASIS	Open Access Same-time Information System.
OATT	Open Access Transmission Tariff, filed with FERC.
OCC	Corporation Commission of the State of Oklahoma.
Ohio Act	Ohio electric restructuring legislation.
Ohio Amendments	Amendments to the Ohio Act adopted in April 2008 which required electric utilities to adjust their rates by filing an ESP with the PUCO.
OHTCo	AEP Ohio Transmission Company, Inc.
OKTCo	AEP Oklahoma Transmission Company, Inc.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OSS	Off-system sales.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
RCRA	Resource Conservation and Recovery Act of 1976, as amended.
REP	Texas retail electricity provider.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
ROE	Return on Equity.
RTO	Regional Transmission Organization.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.

Term	Meaning
SEC	U.S. Securities and Exchange Commission.
S&P	Standard & Poor's Ratings Service.
SO_2	Sulfur dioxide.
SPP	Southwest Power Pool regional transmission organization.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCA	Transmission Coordination Agreement dated January 1, 1997, restated and amended, and as amended and approved by FERC in 2011 by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Act	Texas electric restructuring legislation.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
TVA	Tennessee Valley Authority.
Utility Money Pool	AEP System's Utility Money Pool is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its registrant subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Financial Discussion and Analysis," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio due to the February 2012 PUCO rehearing order.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants and related assets.
- A reduction in the federal statutory tax rate.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of our debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.

- Changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate or amend the Interconnection Agreement and break up or modify the AEP Power Pool.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its registrant subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its registrant subsidiaries expressly disclaim any obligation to update any forward-looking information.

PART I

ITEM 1. BUSINESS

GENERAL

Overview and Description of Subsidiaries

AEP was incorporated under the laws of the State of New York in 1906 and reorganized in 1925. It is a public utility holding company that owns, directly or indirectly, all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries.

The service areas of AEP's public utility subsidiaries cover portions of the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia. The generating and transmission facilities of AEP's public utility subsidiaries are interconnected and their operations are coordinated. Transmission networks are interconnected with extensive distribution facilities in the territories served. The public utility subsidiaries of AEP have traditionally provided electric service, consisting of generation, transmission and distribution, on an integrated basis to their retail customers. Restructuring legislation in Michigan, Ohio and the ERCOT area of Texas has caused AEP public utility subsidiaries in those states to unbundle previously integrated regulated rates for their retail customers.

The AEP System is an integrated electric utility system. As a result, the member companies of the AEP System have contractual, financial and other business relationships with the other member companies, such as participation in the AEP System savings and retirement plans and tax returns, sales of electricity and transportation and handling of fuel. The companies of the AEP System also obtain certain accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost from a common provider, AEPSC.

At December 31, 2011, the subsidiaries of AEP had a total of 18,710 employees. Because it is a holding company rather than an operating company, AEP has no employees. The public utility subsidiaries of AEP are:

APCo

Organized in Virginia in 1926, APCo is engaged in the generation, transmission and distribution of electric power to approximately 960,000 retail customers in the southwestern portion of Virginia and southern West Virginia, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2011, APCo and its wholly owned subsidiaries had 2,176 employees. Among the principal industries served by APCo are paper, rubber, coal mining, textile mill products and stone, clay and glass products. In addition to its AEP System interconnections, APCo is interconnected with the following nonaffiliated utility companies: Carolina Power & Light Company, Duke Carolina and Virginia Electric and Power Company. APCo has several points of interconnection with TVA and has entered into agreements with TVA under which APCo and TVA interchange and transfer electric power over portions of their respective systems. APCo is a member of PJM.

I&M

Organized in Indiana in 1907, I&M is engaged in the generation, transmission and distribution of electric power to approximately 582,000 retail customers in northern and eastern Indiana and southwestern Michigan, and in supplying and marketing electric power at wholesale to other electric utility companies, rural electric cooperatives, municipalities and other market participants. At December 31, 2011, I&M had 2,671 employees. Among the principal industries served are primary metals, transportation equipment, electrical and electronic machinery, fabricated metal products, rubber and chemicals and allied products, rubber products and transportation equipment. In addition to its AEP System interconnections, I&M is interconnected with the following nonaffiliated utility companies: Central Illinois Public Service Company, Duke Ohio, Commonwealth Edison Company, Consumers Energy Company, Illinois Power Company, Indianapolis Power & Light Company, Louisville Gas and Electric Company, Northern Indiana Public Service Company, Duke Indiana and Richmond Power & Light Company. I&M is a member of PJM.

KPCo

Organized in Kentucky in 1919, KPCo is engaged in the generation, transmission and distribution of electric power to approximately 173,000 retail customers in an area in eastern Kentucky, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2011, KPCo had 415 employees. Among the principal industries served are petroleum refining, coal mining and chemical production. In addition to its AEP System interconnections, KPCo is interconnected with the following nonaffiliated utility companies: Kentucky Utilities Company and East Kentucky Power Cooperative Inc. KPCo is also interconnected with TVA. KPCo is a member of PJM.

KGPCo

Organized in Virginia in 1917, KGPCo provides electric service to approximately 47,000 retail customers in Kingsport and eight neighboring communities in northeastern Tennessee. KGPCo does not own any generating facilities and is a member of PJM. It purchases electric power from APCo for distribution to its customers. At December 31, 2011, KGPCo had 50 employees.

OPCo

Organized in Ohio in 1907 and re-incorporated in 1924, OPCo is engaged in the generation, transmission and distribution of electric power to approximately 1,460,000 retail customers in Ohio, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities and other market participants. At December 31, 2011, OPCo had 3,256 employees. Among the principal industries served by OPCo are primary metals, chemicals and allied products, health services, electronic machinery, petroleum refining, and rubber and plastic products. In addition to its AEP System interconnections, OPCo is interconnected with the following nonaffiliated utility companies: Duke Ohio, The Cleveland Electric Illuminating Company, Dayton Power and Light Company, Duquesne Light Company, Kentucky Utilities Company, Monongahela Power Company, Ohio Edison Company, The Toledo Edison Company and West Penn Power Company. OPCo is a member of PJM.

On December 31, 2011, CSPCo merged with and into OPCo with OPCo being the surviving entity. For purposes of this Annual Report on Form 10-K, all prior reported amounts have been recast as if the merger occurred on the first day of the earliest reporting period. All contracts, subsidiaries and operations of CSPCo are now reflected as part of OPCo.

PSO

Organized in Oklahoma in 1913, PSO is engaged in the generation, transmission and distribution of electric power to approximately 532,000 retail customers in eastern and southwestern Oklahoma, and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2011, PSO had 1,131 employees. Among the principal industries served by PSO are paper manufacturing and timber products, natural gas and oil extraction, transportation, non-metallic mineral production, oil refining and steel processing. In addition to its AEP System interconnections, PSO is interconnected with Empire District Electric Company, Oklahoma Gas and Electric Company, Southwestern Public Service Company and Westar Energy, Inc. PSO is a member of SPP.

SWEPCo

Organized in Delaware in 1912, SWEPCo is engaged in the generation, transmission and distribution of electric power to approximately 521,000 retail customers in northeastern and panhandle of Texas, northwestern Louisiana and western Arkansas and in supplying and marketing electric power at wholesale to other electric utility companies, municipalities, rural electric cooperatives and other market participants. At December 31, 2011, SWEPCo had 1,462 employees. Among the principal industries served by SWEPCo are natural gas and oil production, petroleum refining, manufacturing of pulp and paper, chemicals, food processing, and metal refining. The territory served by SWEPCo also includes several military installations, colleges and universities. SWEPCo also owns and operates a lignite coal mining operation. In addition to its AEP System interconnections, SWEPCo is interconnected with CLECO, Empire District Electric Company, Entergy Corp. and Oklahoma Gas & Electric Company. SWEPCo is a member of SPP.

TCC

Organized in Texas in 1945, TCC is engaged in the transmission and distribution of electric power to approximately 787,000 retail customers through REPs in southern Texas. TCC has sold all of its generation assets. At December 31, 2011, TCC had 997 employees. Among the principal industries served by TCC are chemical and petroleum refining, chemicals and allied products, oil and gas extraction, food processing, metal refining, plastics and machinery equipment. In addition to its AEP System interconnections, TCC is a member of ERCOT.

TNC

Organized in Texas in 1927, TNC is engaged in the transmission and distribution of electric power to approximately 186,000 retail customers through REPs in west and central Texas. TNC's generating capacity has been transferred to an affiliate at TNC's cost pursuant to an agreement effective through 2027. At December 31, 2011, TNC had 319 employees. Among the principal industries served by TNC are petroleum refining, agriculture and the manufacturing or processing of cotton seed products, oil products, precision and consumer metal products, meat products and gypsum products. The territory served by TNC also includes several military installations and correctional facilities. In addition to its AEP System interconnections, TNC is a member of ERCOT.

WPCo

Organized in West Virginia in 1883 and reincorporated in 1911, WPCo provides electric service to approximately 41,000 retail customers in northern West Virginia. WPCo does not own any generating facilities. WPCo is a member of PJM. It purchases electric power from OPCo for distribution to its customers. At December 31, 2011, WPCo had 52 employees. In February 2012, WPCo filed an application with the FERC seeking authorization to merge with and into APCo. The merger is expected to require the approval of the WVPSC and the Virginia SCC.

AEGCo

Organized in Ohio in 1982, AEGCo is an electric generating company. AEGCo sells power at wholesale to OPCo, I&M and KPCo. AEGCo has no employees.

Service Company Subsidiary

AEP also owns a service company subsidiary, AEPSC. AEPSC provides accounting, administrative, information systems, engineering, financial, legal, maintenance and other services at cost to the AEP affiliated companies. The executive officers of AEP and certain of its public utility subsidiaries are employees of AEPSC. At December 31, 2011, AEPSC had 4,977 employees.

CLASSES OF SERVICE

The principal classes of service from which the public utility subsidiaries of AEP derive revenues and the amount of such revenues during the year ended December 31, 2011 are as follows:

Description	AEP System (a)	APCo	I&M	OPCo	PSO	SWEPCo
			(in thousands)			
Utility Operations						
Retail Sales						
Residential Sales	$ 5,207,000	$ 1,107,199	$ 503,554	$ 1,680,179	$ 572,404	$ 554,663
Commercial Sales	3,319,000	535,040	369,471	1,077,742	364,701	411,652
Industrial Sales	2,953,000	638,854	412,562	979,424	241,026	288,474
PJM Net Charges	(74,000)	(23,696)	(14,485)	(30,768)	-	-
Provision for Rate Refund	7,000	-	(461)	6,035	(158)	1,604
Other Retail Sales	205,000	64,741	6,693	17,714	78,722	8,118
Total Retail	11,617,000	2,322,138	1,277,334	3,730,326	1,256,695	1,264,511
Wholesale						
Off-System Sales	2,067,000	504,955	499,291	667,593	42,241	259,877
Transmission	187,000	(19,723)	(14,531)	(26,697)	31,903	47,782
Total Wholesale	2,254,000	485,232	484,760	640,896	74,144	307,659
Other Electric Revenues	161,000	29,649	8,353	36,008	14,713	22,022
Other Operating Revenues	59,000	9,942	15,086	18,395	3,644	2,019
Sales to Affiliates	-	358,264	429,237	1,005,486	14,192	57,615
Total Utility Operating Revenues	14,091,000	3,205,225	2,214,770	5,431,111	1,363,388	1,653,826
Other	1,025,000	-	-	-	-	-
Total Revenues	$ 15,116,000	$ 3,205,225	$ 2,214,770	$ 5,431,111	$ 1,363,388	$ 1,653,826

(a) Includes revenues of other subsidiaries not shown. Intercompany transactions have been eliminated for the year ended December 31, 2011.

FINANCING

General

Companies within the AEP System generally use short-term debt to finance working capital needs. Short-term debt may also be used to finance acquisitions, construction and redemption or repurchase of outstanding securities until such needs can be financed with long-term debt. In recent history, short-term funding needs have been provided for by cash on hand, borrowing under AEP's revolving credit agreements and AEP's commercial paper program. Funds are made available to subsidiaries under the AEP corporate borrowing program. Certain public utility subsidiaries of AEP also sell accounts receivable to provide liquidity. See "Financial Condition" section Management's Financial Discussion and Analysis, included in the 2011 Annual Reports, under the heading entitled Financial Condition for additional information concerning short-term funding and our access to bank lines of credit, commercial paper and capital markets.

AEP's revolving credit agreements (which backstop the commercial paper program) include covenants and events of default typical for this type of facility, including a maximum debt/capital test and, for AEP and its significant subsidiaries, a $50 million cross-acceleration provision. At December 31, 2011, AEP was in compliance with its debt covenants. With the exception of a voluntary bankruptcy or insolvency, any event of default has either or both a cure period or notice requirement before termination of the agreements. A voluntary bankruptcy or insolvency of AEP or one of its significant subsidiaries would be considered an immediate termination event. See Management's Financial Discussion and Analysis, included in the 2011 Annual Reports, under the heading entitled Financial Condition for additional information with respect to AEP's credit agreements.

AEP's subsidiaries have also utilized, and expect to continue to utilize, additional financing arrangements, such as securitization financings, leasing arrangements, including the leasing of coal transportation equipment and facilities.

ENVIRONMENTAL AND OTHER MATTERS

General

AEP's subsidiaries are currently subject to regulation by federal, state and local authorities with regard to air and water-quality control and other environmental matters, and are subject to zoning and other regulation by local authorities. The environmental issues that we believe are potentially material to the AEP system are outlined below.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control mobile and stationary sources of air emissions. The major CAA programs affecting our power plants are described below. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Acid Rain Program

The 1990 Amendments to the CAA include a cap-and-trade emission reduction program for SO_2 emissions from power plants. By 2000, the program established a nationwide cap on power plant SO_2 emissions of 8.9 million tons per year. The 1990 Amendments also contain requirements for power plants to reduce NO_x emissions through the use of available combustion controls.

The success of the SO_2 cap-and-trade program encouraged the Federal EPA and the states to use it as a model for other emission reduction programs. We continue to meet our obligations under the Acid Rain Program through the installation of controls, use of alternate fuels and participation in the emissions allowance markets. Subsequent programs developed by the Federal EPA have imposed more stringent SO_2 and NOx emission reduction requirements than the Acid Rain Program on many of our facilities. We have installed additional controls and taken other actions to achieve compliance with these programs.

National Ambient Air Quality Standards

The CAA requires the Federal EPA to review the available scientific data for criteria pollutants periodically and establish a concentration level in the ambient air for those substances that is adequate to protect the public health and welfare with an extra safety margin. The Federal EPA also can list additional pollutants and develop concentration levels for them. These concentration levels are known as national ambient air quality standards (NAAQS).

Each state identifies the areas within its boundaries that meet the NAAQS (attainment areas) and those that do not (nonattainment areas). Each state must develop a state implementation plan (SIP) to bring nonattainment areas into compliance with the NAAQS and maintain good air quality in attainment areas. All SIPs are submitted to the Federal EPA for approval. If a state fails to develop adequate plans, the Federal EPA develops and implements a plan. As the Federal EPA reviews the NAAQS and establishes new concentration levels, the attainment status of areas can change and states may be required to develop new SIPs. In 2008, the Federal EPA issued revised NAAQS for both ozone and fine particulate matter ($PM_{2.5}$). The $PM_{2.5}$ standard was remanded by the D.C. Circuit Court of Appeals, and a new standard is under development. A new ozone standard is also under development and is expected to be finalized in 2013. The Federal EPA also adopted a new short-term standard for SO_2 in 2010, a lower standard for NO_2 in 2010, and a lower standard for lead in 2008. The existing standard for carbon monoxide was retained in 2011. The states will develop new SIPs for these standards, which could result in additional emission reductions being required from our facilities.

In 2005, the Federal EPA issued the Clean Air Interstate Rule (CAIR), which requires additional reductions in SO_2 and NO_x emissions from power plants and assists states developing new SIPs to meet the NAAQS. For additional information regarding CAIR, see Management's Financial Discussion and Analysis under the headings entitled Environmental Matters – Clean Air Act Requirements. In August 2011, the Federal EPA issued a final rule to replace CAIR (the Cross State Air Pollution Rule (CSAPR)) that would impose new and more stringent requirements to control SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 27 states and the District of Columbia. Petitions for review were filed with the U.S. Court of Appeals for the District of Columbia

Circuit, and CSAPR was stayed. CAIR remains in effect until further order from the court. For additional information regarding CSAPR, see Management's Financial Discussion and Analysis under the headings entitled Environmental Matters – Clean Air Act Requirements.

Hazardous Air Pollutants

As a result of the 1990 Amendments to the CAA, the Federal EPA investigated hazardous air pollutant (HAP) emissions from the electric utility sector and submitted a report to Congress, identifying mercury emissions from coal-fired power plants as warranting further study. In 2011, the Federal EPA issued a final rule setting Maximum Achievable Control Technology (MACT) standards for new and existing coal and oil-fired utility units and New Source Performance Standards (NSPS) for emissions from new and modified power plants. For additional information regarding the Utility MACT, see Management's Financial Discussion and Analysis under the headings entitled Environmental Matters – Clean Air Act Requirements.

Regional Haze

The CAA establishes visibility goals for certain federally designated areas, including national parks, and requires states to submit SIPs that will demonstrate reasonable progress toward preventing impairment of visibility in these areas (Regional Haze program). In 2005, the Federal EPA issued its Clean Air Visibility Rule (CAVR), detailing how the CAA's best available retrofit technology requirements will be applied to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. For additional information regarding CAVR, see Management's Financial Discussion and Analysis under the headings entitled Environmental Matters – Clean Air Act Requirements.

In December 2011, the Federal EPA issued a partial approval and partial disapproval of the Oklahoma SIP for Regional Haze, and a Federal Implementation Plan (FIP) for the SO_2 requirements that were disapproved. The Federal EPA has also proposed to disapprove the best available retrofit technology determinations for the coal-fired power plants in Arkansas, but has not proposed a FIP for these units. The requirements of the FIP that apply to our Oklahoma units impose significantly greater costs than would have been incurred under the Oklahoma SIP. We are unable to predict whether a FIP will be developed to satisfy CAVR in Arkansas or how it may affect our compliance obligations for the Regional Haze program.

Greenhouse Gas Emissions

In the absence of comprehensive climate change legislation, the Federal EPA has taken action to regulate CO_2 emissions under the existing requirements of the CAA. Such actions are being legally challenged by numerous parties. For additional information regarding the Federal EPA action taken to regulate CO_2 emissions, see Management's Financial Discussion and Analysis under the headings entitled Environmental Matters – Clean Air Act Requirements.

Our fossil fuel-fired generating units are large sources of CO_2 emissions. If substantial CO_2 emission reductions are required, there will be significant increases in capital expenditures and operating costs which would hasten the ultimate retirement of older, less-efficient, coal-fired units. To the extent we install additional controls on our generating plants to limit CO_2 emissions and receive regulatory approvals to increase our rates, return on capital investment would have a positive effect on future earnings. Prudently incurred capital investments made by our subsidiaries in rate-regulated jurisdictions to comply with legal requirements and benefit customers are generally included in rate base for recovery and earn a return on investment. We would expect these principles to apply to investments made to address new environmental requirements. However, requests for rate increases reflecting these costs can affect us adversely because our regulators could limit the amount or timing of increased costs that we would recover through higher rates. To the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear generation, it could reduce our off-system sales or cause us to lose customers in jurisdictions that permit customers to choose their supplier of generation service.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain states, including Ohio, Michigan, Texas and Virginia, passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements. We are taking steps to comply with these requirements primarily through entering into power supply agreements giving us access to power generated by wind turbines.

Clean Water Act Requirements

Our operations are also subject to the Federal Clean Water Act, which prohibits the discharge of pollutants into waters of the United States except pursuant to appropriate permits, and regulates systems that withdraw surface water for use in our power plants. In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. We submitted comments on the proposal in July and August 2011.

In July 2007, the Federal EPA affirmed the requirement that permitting agencies develop best professional judgment (BPJ) controls for existing facility cooling water intake structures that reflect the best technology available for minimizing adverse environmental impact. The result is that the BPJ control standard for cooling water intake structures in effect prior to the rule is used as the applicable standard by permitting agencies pending finalization of revised rules by the Federal EPA.

In April 2009, the U.S. Supreme Court issued a decision that allows the Federal EPA the discretion to rely on cost-benefit analysis in setting national performance standards and in providing for cost-benefit variances from those standards as part of the regulations. We cannot predict if or how the Federal EPA will apply this decision to any revision of the regulations or what effect it may have on similar requirements adopted by the states. We expect the Federal EPA to issue revised rules in 2012.

The Federal EPA is also engaged in rulemaking to update the technology-based standards that govern discharges from new and existing power plants under the Clean Water Act's National Pollutant Discharge Elimination System program. These standards were last updated over 20 years ago, and the Federal EPA has issued two rounds of information collection requests to inform its rulemaking. In October 2009, the Federal EPA issued a final report for the power plant sector and determined that revisions to its existing standards are necessary, but the Federal EPA has not yet proposed any specific requirements. Until new standards are proposed, we cannot predict the outcome or impact of these rules on our operations.

Coal Ash Regulation

Our operations produce a number of different coal combustion products, including fly ash, bottom ash, gypsum and other materials. The Federal EPA completed an extensive study of the characteristics of coal ash in 2000 and concluded that combustion wastes do not warrant regulation as hazardous waste. In December 2008, the breach of a dike at the Tennessee Valley Authority's Kingston Station resulted in a spill of several million cubic yards of ash into a nearby river and onto private properties, prompting federal and state reviews of ash storage and disposal practices at many coal-fired electric generating facilities, including ours. AEP operates 37 ash ponds and we manage these ponds in a manner that complies with state and local requirements, including dam safety rules designed to assure the structural integrity of these facilities. We also operate a number of dry disposal facilities in accordance with state standards, including ground water monitoring and other applicable standards. In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. For additional information regarding the Federal EPA action taken to regulate the disposal and beneficial re-use of coal combustion residuals and the potential impact on our operations, see Management's Financial Discussion and Analysis under the headings entitled Environmental Matters – Coal Combustion Residual Rule.

Greenhouse Gases – Position and Strategy

We continue to support a federal legislative approach to energy policy as the most effective means of reducing emissions of CO_2 and other greenhouse gases (generally referred to as CO_2) that recognizes that a reliable and affordable electricity supply is vital to economic recovery and growth. We do not believe regulating CO_2 emissions under the Clean Air Act is the appropriate solution. During the past decade, we have taken voluntary actions to reduce and offset our CO_2 emissions. Unfortunately, two of the voluntary programs that helped businesses such as AEP to set quantitative commitments no longer exist. The Federal EPA's Climate Leaders Program and the Chicago Climate Exchange both ended their reduction obligations at the end of 2010. However, through these programs and others, we voluntarily reduced our CO_2 emissions by approximately 94 million metric tons during the 2003 to 2010 period. We expect our emissions to continue to decline over time as we diversify our generating sources and operate fewer coal units. The projected decline in coal-fired generation is due to a number of factors including the ongoing cost of operating older units, increasing environmental regulations requiring significant capital investments and changing commodity market fundamentals. Our strategy for this transformation is to protect the reliability of the electric system and reduce our emissions by pursuing multiple options. These include diversifying our fuel portfolio and generating more electricity from natural gas, increasing energy efficiency and investing in renewable resources, where there is regulatory support. Meanwhile the Federal EPA began regulating CO_2 emissions from large stationary sources such as power plants in 2012 under the NSR prevention of significant deterioration and Title V operating permit programs.

For additional information on legislative and regulatory responses to greenhouse gases, including limitations on CO_2 emissions, see Management's Financial Discussion and Analysis under the headings entitled Environmental Matters – Global Warming. Specific steps taken to reduce CO_2 emissions include the following:

Renewable Sources of Energy

Some of our states have laws or commission orders that establish requirements or goals for renewable and/or alternative energy (Louisiana, Ohio, Arkansas, Michigan, West Virginia, Texas, Indiana, Virginia and Oklahoma) and we are taking steps to comply with these rules in a timely fashion. A key sustainability commitment we made was to increase renewable power by an additional 2,000 MW from 2007 levels by 2011, subject to regulatory approval. By the end of 2011, AEP secured only 1,500 MW of renewable power through power purchase agreements.

End User Energy Efficiency

Energy efficiency is a high priority for AEP because it can be a cost-effective way to reduce energy demand and potentially delay the need for new power plants. We work collaboratively with regulators, technical experts, environmental groups and others to develop and implement efficiency and demand response programs. From 2008 through 2011, we have achieved approximately 716 MW and 1,972,000 MWH of demand and energy reductions, respectively. We have an internal goal to reduce 1,000 MW of demand and 2,250,000 MWH of energy consumption by year-end 2012. We expect to surpass our energy reduction goal subject to regulatory approvals, appropriate cost recovery, and continued customer demand for programs. In 2011, we invested over $115 million throughout most of our service territory in energy efficiency and demand response initiatives.

gridSMART®

AEP's *gridSMART®* initiative is designed to demonstrate the potential benefits of the smart grid by integrating advanced grid technologies into existing electric networks. AEP is deploying smart grid technologies in several jurisdictions with regulatory support.

- AEP Ohio is deploying a comprehensive suite of smart grid technologies in an innovative demonstration project with 110,000 customers. The $150 million project is being funded through a $75 million federal grant, PUCO cost recovery support and vendor in-kind contributions.
- AEP Texas is deploying a one million meter smart grid network, along with $1 million in energy use display devices for low income customers. The $308 million project is targeted for completion by the end of 2013. We are recovering the costs through an 11-year surcharge.
- I&M has deployed a smart grid network to 10,000 customers. The $7 million project was funded pursuant to a settlement agreement approved by the IURC.
- PSO is deploying a smart meter network and grid management technologies to approximately 14,000 customers. The project is being financed through an $8.75 million American Reinvestment and Recovery Act low-interest loan from the Oklahoma Department of Commerce with $2 million annual revenues for cost recovery approved by the Oklahoma Corporation Commission.

Current and Projected CO_2 Emission

Our total CO_2 emissions in 2010 (including our ownership in the Kyger Creek and Clifty Creek plants) were approximately 140 million metric tons. Our 2011 emissions remained flat at approximately 141 million metric tons. We expect overall increases in CO_2 emissions during the next few years to be small, if any, as our sales and generation rebound somewhat from recession lows in 2009. However, over much of the remainder of the decade we expect emissions to decline as modest sales growth is offset by retirements of older, less efficient coal-fired units and increased utilization of natural gas.

Corporate Governance

Our Board of Directors continually reviews the risks posed by and our actions in response to environmental issues and in connection with its assessment of our strategic plan. The Board of Directors is frequently informed of any new material environmental issues, including changes to regulations and proposed legislation. The Board's Committee on Directors and Corporate Governance oversees the company's annual Corporate Accountability Report, which includes information on environmental issues.

Other Environmental Issues and Matters

- Litigation with the federal and/or certain state governments and certain special interest groups regarding regulated air emissions and/or whether emissions from coal-fired generating plants cause or contribute to global warming. See Management's Financial Discussion and Analysis under the heading entitled Litigation – Environmental Litigation and Note 5 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies, included in the 2011 Annual Reports, for further information.
- CERCLA, which imposes costs for environmental remediation upon owners and previous owners of sites, as well as transporters and generators of hazardous material disposed of at such sites. See Note 5 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies, included in the 2011 Annual Reports, under the heading entitled The Comprehensive Environmental Response Compensation and Liability Act (Superfund) and State Remediation for further information.

Environmental Investments

Investments related to improving AEP System plants' environmental performance and compliance with air and water quality standards during 2009, 2010 and 2011 and the current estimates for 2012, 2013 and 2014 are shown below, in each case excluding equity AFUDC and capitalized interest. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends and the ability to access capital. AEP expects to make substantial investments in future years in addition to the amounts set forth below in connection with the modification and addition of facilities at generating plants for environmental quality controls. Such future investments are needed in order to comply with air and water quality standards that have been adopted and have deadlines for compliance after 2011 or have been proposed and may be adopted. Future investments could be significantly greater if emissions reduction requirements are accelerated or otherwise become more onerous or if CO_2 becomes regulated. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery those costs could adversely affect future results of operations and cash flows, and possibly financial condition. The cost of complying with applicable environmental laws, regulations and rules is expected to be material to the AEP System. See Management's Financial Discussion and Analysis under the heading entitled Environmental Matters and Note 5 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, included in the 2011 Annual Reports, for more information regarding environmental expenditures in general.

Historical and Projected Environmental Investments

	2009 Actual	2010 Actual	2011 Actual	2012 Estimate	2013 Estimate	2014 Estimate
			(in thousands)			
Total AEP System (a)	$ 457,200	$ 303,800	$ 186,800	$ 510,700	$ 999,000	$ 1,100,000
APCo	191,900	202,700	68,900	77,600	77,700	80,300
I&M	19,600	8,100	5,900	89,800	148,200	148,000
OPCo	224,800	97,400	63,000	122,800	187,300	128,700
PSO	1,000	1,200	6,500	43,400	134,600	164,600
SWEPCo (b)	10,700	(10,500)	11,000	75,700	230,500	288,100

(a) Includes expenditures of the subsidiaries shown and other subsidiaries not shown. The figures reflect construction expenditures, not equity investments in subsidiary companies. Excludes discontinued operations.

(b) SWEPCo 2010 actual environmental cost includes reclassifications of project costs for suspended capital projects.

Electric and Magnetic Fields

EMF are found everywhere there is electricity. Electric fields are created by the presence of electric charges. Magnetic fields are produced by the flow of those charges. This means that EMF are created by electricity flowing in transmission and distribution lines, electrical equipment, household wiring and appliances. A number of studies in the past have examined the possibility of adverse health effects from EMF. While some of the epidemiological studies have indicated some association between exposure to EMF and health effects, none has produced any conclusive evidence that EMF does or does not cause adverse health effects.

Management cannot predict the ultimate impact of the question of EMF exposure and adverse health effects. If further research shows that EMF exposure contributes to increased risk of cancer or other health problems, or if the courts conclude that EMF exposure harms individuals and that utilities are liable for damages, or if states limit the strength of magnetic fields to such a level that the current electricity delivery system must be significantly changed, then the results of operations and financial condition of AEP and its operating subsidiaries could be materially adversely affected unless these costs can be recovered from customers.

UTILITY OPERATIONS

GENERAL

Utility operations constitute most of AEP's business operations. Utility operations include (a) the generation, transmission and distribution of electric power to retail customers and (b) the supplying and marketing of electric power at wholesale (through the electric generation function) to other electric utility companies, municipalities and other market participants. AEPSC, as agent for AEP's public utility subsidiaries, performs marketing, generation dispatch, fuel procurement and power-related risk management and trading activities.

ELECTRIC GENERATION

Facilities

As of December 31, 2011, AEP's public utility subsidiaries owned or leased approximately 37,000 MW of domestic generation. See Item 2 – Properties for more information regarding AEP's generation capacity.

AEP Power Pool

APCo, I&M, KPCo, OPCo and AEPSC are parties to the Interconnection Agreement, which was originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975, 1979 (twice) and 1980. This agreement defines how the member companies share the costs and benefits associated with their generating plants. This sharing is based upon each company's "member load ratio." The member load ratio is calculated monthly by dividing each company's highest monthly peak demand for the last twelve months by the aggregate of the highest monthly peak demand for the last twelve months for all member companies. The member load ratio multiplied by the aggregate generation capacity of all the member companies determines each member company's capacity obligation. The difference between each member company's obligation and its own generation capacity determines the capacity surplus or deficit of each member company. The agreement requires the deficit companies to make monthly capacity equalization payments to the surplus companies based on the surplus companies' average fixed cost of generation. Member companies that deliver energy to other member companies to meet their internal load requirements are reimbursed at average variable costs. In addition, all member companies share off-system sales margins based upon each member company's member load ratio. Consequently, the agreement provides a strong risk sharing and mitigation arrangement among the member companies. As of December 31, 2011, the member-load-ratios were as follows:

	Peak Demand	Member-Load Ratio
	(MWs)	(%)
APCo	7,248	30.5
I&M	4,837	20.4
KPCo	1,522	6.4
OPCo	10,148	42.7

APCo, I&M, KPCo and OPCo are parties to the AEP System Interim Allowance Agreement (Allowance Agreement), which has been approved by the FERC and provides, among other things, for the transfer of SO_2 emission allowances associated with transactions under the Interconnection Agreement. The following table shows the net (credits) or charges allocated among the parties under the Interconnection Agreement during the years ended December 31, 2011, 2010 and 2009:

	2011	2010	2009
		(in thousands)	
APCo	$ 632,100	$ 757,900	$ 668,700
I&M	(183,700)	(236,900)	(100,900)
KPCo	48,400	49,400	31,600
OPCo	(496,800)	(570,400)	(599,400)

Notification of Termination of the AEP Power Pool

The regulatory landscape and business environment have changed extensively since the Interconnection Agreement was originally executed in 1951. These changes include:

- Evolving environmental regulations.
- The introduction of "open access" to transmission facilities.
- The implementation of RTOs, including PJM, which is a robust generation power pool that has generating capacity of over 167,000 MWs.
- Movement towards industry deregulation.
- The planned separation of OPCo's generation and power marketing businesses from its transmission and distribution businesses.
- Increased competition in wholesale generation markets.
- The effects of these changes on such things as costs, load and the array of supply and demand-side resources available to the AEP-East operating companies today.

Consequently, in December 2010, each AEP Power Pool member gave written notice to the other members, and AEPSC, the Pool's agent, of its decision to terminate the Interconnection Agreement, effective January 1, 2014 or such other date as approved by FERC, subject to state regulatory input. The Pool Agreement members unanimously have agreed to waive the full three-year notice provision. Because the Interconnection Agreement is a rate schedule on file at FERC, its termination will not be effective until accepted for filing by FERC. Final resolution could involve bilateral contracts or sales of generating assets from surplus members to deficit members.

Additionally, the AEP East companies have decided to terminate the Allowance Agreement.

CSW Operating Agreement

PSO, SWEPCo and AEPSC are parties to the CSW Operating Agreement, which has been approved by the FERC. The CSW Operating Agreement requires these public utility subsidiaries to maintain adequate annual planning reserve margins and requires the subsidiaries that have capacity in excess of the required margins to make such capacity available for sale to other public utility subsidiary parties as capacity commitments. Parties are compensated for energy delivered to the 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 in their region are generally shared based on the amount of energy each west zone public utility subsidiary contributes that is sold to third parties.

The following table shows the net (credits) or charges allocated among the parties under the CSW Operating Agreement during the years ended December 31, 2011, 2010 and 2009:

	2011	2010	2009
		(in thousands)	
PSO	$ 33,091	$ 20,222	$ (22,762)
SWEPCo	(33,091)	(20,222)	22,762

Power generated by or allocated or provided under the Interconnection Agreement or CSW Operating Agreement to any public utility subsidiary is primarily sold to customers by such public utility subsidiary at rates approved by the public utility commission in the jurisdiction of sale. See Regulation – Rates under Item 1, Utility Operations.

Under both the Interconnection Agreement and CSW Operating Agreement, power that is not needed to serve the native load of our public utility subsidiaries is sold in the wholesale market by AEPSC on behalf of those subsidiaries. See Risk Management and Trading, below, for a discussion of the trading and marketing of such power.

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

Risk Management and Trading

As agent for AEP's public utility subsidiaries, AEPSC sells excess power into the market and engages in power, natural gas, coal and emissions allowances risk management and trading activities focused in regions in which AEP traditionally operates and in adjacent regions. These activities primarily involve the purchase and sale of electricity (and to a lesser extent, natural gas, coal and emissions allowances) under physical forward contracts at fixed and variable prices. These contracts include physical transactions, over-the-counter swaps and exchange-traded futures and options. The majority of physical forward contracts are typically settled by netting into offsetting contracts. These transactions are executed with numerous counterparties or on exchanges. Counterparties and exchanges may require cash or cash related instruments to be deposited on these transactions as margin against open positions. As of December 31, 2011, counterparties have posted approximately $16 million in cash, cash equivalents or letters of credit with AEPSC for the benefit of AEP's public utility subsidiaries (while, as of that date, AEP's public utility subsidiaries had posted approximately $171 million with counterparties and exchanges). Since open trading contracts are valued based on market prices of various commodities, exposures change daily. See Management's Financial Discussion and Analysis, included in the 2011 Annual Reports, under the heading entitled Quantitative and Qualitative Disclosures About Risk Management Activities for additional information.

Fuel Supply

The following table shows the sources of fuel used by the AEP System:

	Years Ended December 31,		
	2011	2010	2009
Coal and Lignite	78%	82%	88%
Natural Gas	11%	8%	6%
Nuclear	10%	9%	5%
Hydroelectric and other	<1%	<1%	1%

Price increases in one or more fuel sources relative to other fuels may result in increased use of other fuels. The decreased generation of nuclear power in 2009 is primarily related to a 2008 forced outage caused by a low pressure turbine blade failure event and the impacted unit coming back on line in 2010.

Coal and Lignite

AEP's public utility subsidiaries procure coal and lignite under a combination of purchasing arrangements including long-term contracts, affiliate operations and spot agreements with various producers and coal trading firms. Coal consumption was in line with the projected fuel usage in 2011 and coal inventories ended 2011 near target levels.

Management believes that AEP's public utility subsidiaries will be able to secure and transport coal and lignite of adequate quality and in adequate quantities to operate their coal and lignite-fired units. Through its public utility subsidiaries, as of December 31, 2011, AEP owned, leased or controlled more than 7,600 railcars, 634 barges, 16 towboats and a coal handling terminal with 18 million tons of annual capacity to move and store coal for use in our generating facilities. See AEP River Operations for a discussion of AEP's for-profit coal and other dry-bulk commodity transportation operations that are not part of AEP's Utility Operations segment.

Spot market prices for certain coals utilized by AEP fluctuated in a fairly narrow band throughout much of the year, but softened noticeably in the fourth quarter. The general increase in spot coal prices seen over the past few years has been supported by higher international demand for U.S. coals, and increased mining costs related to regulatory and permitting issues. Most of the coal purchased by AEP is procured through term contracts. The price paid under a number of these contracts is often lower than the spot market price for similar coal. As term contracts expire they are replaced with new agreements, often at higher prices. The price paid for coal delivered in 2011 increased from the prior year, reflective of market price trending.

The following table shows the amount of coal and lignite delivered to the AEP System plants during the past three years and the average delivered price of coal purchased by AEP System companies:

	Years Ended December 31,		
	2011	2010	2009
Total Coal Delivered to AEP System Plants (thousands of tons)	62,956	64,614	75,909
Average Price per Ton of Purchased Coal	$ 46.76	$ 44.82	$ 49.54

The coal supplies at AEP System plants vary from time to time depending on various factors, including, but not limited to, demand for electric power, unit outages, transportation infrastructure limitations, space limitations, plant coal consumption rates, availability of acceptable coals, labor issues and weather conditions which may interrupt production or deliveries. At December 31, 2011, the System's coal inventory was approximately 39 days of full load burn.

In cases of emergency or shortage, AEP has developed programs to conserve coal supplies at its plants. Such programs have been filed and reviewed with federally approved electric reliability organizations. In some cases, the relevant state regulatory agency has prescribed actions to be taken under specified circumstances by System companies, subject to the jurisdiction of such agency.

The FERC has adopted regulations relating, among other things, to the circumstances under which, in the event of fuel emergencies or shortages, it might order electric utilities to generate and transmit electric power to other regions or systems experiencing fuel shortages, and to ratemaking principles by which such electric utilities would be compensated. In addition, the federal government is authorized, under prescribed conditions, to reallocate coal and to require the transportation thereof, for the use at power plants or major fuel-burning installations experiencing fuel shortages.

Natural Gas

Through its public utility subsidiaries, AEP consumed nearly 167 billion cubic feet of natural gas during 2011 for generating power. This represents an increase of 25% from 2010 and continues a trend that began in 2010 when AEP's natural gas consumption increased 40% above the 2009 level. The increased natural gas consumption is primarily due to the addition of the Stall natural gas combined cycle unit at SWEPCo in June 2010, along with increased operation of the Lawrenceburg and Waterford combined cycle units in the East. APCo's Dresden Plant, a new 580 MW combined-cycle natural gas generating unit in Ohio, was completed and placed in service in January 2012. The efficient heat rates of these units coupled with sustained lower natural gas prices have supported the increased operation of AEP's combined cycle natural gas units during 2011. Increased production from shale gas development continues to place downward pressure on natural gas prices as a result of more abundant supplies, making power generated from these units more economic. Many of the natural gas-fired power plants are connected to at least two pipelines, which allows greater access to competitive supplies and improves delivery reliability. A portfolio of term, monthly, seasonal firm and daily peaking purchase and transportation agreements (that are entered into on a competitive basis and based on market prices) supplies natural gas requirements for each plant, as appropriate.

The following table shows the amount of natural gas delivered to the AEP System plants during the past three years and the average delivered price of natural gas purchased by AEP System companies:

	Years Ended December 31,		
	2011	2010	2009
Total Natural Gas Delivered to AEP System Plants (BCFs)	166.8	133.6	95.7
Average Price per MMBtu of Purchased Natural Gas	$ 4.48	$ 4.80	$ 4.17

Nuclear

I&M has made commitments to meet the current nuclear fuel requirements of the Cook Plant. I&M has made and will make purchases of uranium in various forms in the spot, short-term, and mid-term markets. I&M also continues to lease a portion of its nuclear fuel.

For purposes of the storage of high-level radioactive waste in the form of spent nuclear fuel, I&M completed modifications to its spent nuclear fuel storage pool more than 10 years ago. I&M anticipates that the Cook Plant has sufficient storage capacity for its spent nuclear fuel to permit normal operations through 2013. I&M has entered into an agreement to provide for onsite dry cask storage. Initial loading of spent nuclear fuel into the dry casks is scheduled to begin in 2012.

Nuclear Waste and Decommissioning

As the owner of the Cook Plant, I&M has a significant future financial commitment to dispose of spent nuclear fuel and decommission and decontaminate the plant safely. The cost to decommission a nuclear plant is affected by NRC regulations and the spent nuclear fuel disposal program. In 2009, when the most recent study was done, the estimated cost of decommissioning and disposal of low-level radioactive waste for the Cook Plant ranged from $831 million to $1.5 billion in 2009 non-discounted dollars. At December 31, 2011, the total decommissioning trust fund balance for the Cook Plant was approximately $1.3 billion. The balance of funds available to decommission Cook Plant will differ based on contributions and investment returns. The ultimate cost of retiring the Cook Plant may be materially different from estimates and funding targets as a result of the:

- Type of decommissioning plan selected.
- Escalation of various cost elements (including, but not limited to, general inflation and the cost of energy).
- Further development of regulatory requirements governing decommissioning.
- Technology available at the time of decommissioning differing significantly from that assumed in studies.
- Availability of nuclear waste disposal facilities.
- Availability of a DOE facility for permanent storage of spent nuclear fuel.

Accordingly, management is unable to provide assurance that the ultimate cost of decommissioning the Cook Plant will not be significantly different than current projections. We will seek recovery from customers through our regulated rates if actual decommissioning costs exceed our projections. See Note 5 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies under the heading Nuclear Contingencies, included in the 2011 Annual Reports, for information with respect to nuclear waste and decommissioning.

Low-Level Radioactive Waste

The LLWPA mandates that the responsibility for the disposal of low-level radioactive waste rests with the individual states. Low-level radioactive waste consists largely of ordinary refuse and other items that have come in contact with radioactive materials. Michigan does not currently have a disposal site for such waste available. I&M cannot predict when such a site may be available, but Utah licenses a low-level radioactive waste disposal site which currently accepts low-level radioactive waste from Michigan. I&M ships some of its low level waste to a facility in Utah. There is currently no set date limiting I&M's access to the Utah facility. I&M stores the remaining type of low-level waste onsite. In order to have capacity for the duration of its licensed operation of Cook Plant for onsite storage of waste not shipped to Utah, I&M will have to modify its existing facilities sometime in the next ten to fifteen years.

Structured Arrangements Involving Capacity, Energy and Ancillary Services

In January 2000, OPCo and NPC, an affiliate of Buckeye, entered into an agreement relating to the construction and operation of a 510 MW gas-fired electric generating peaking facility to be owned by NPC, called the Mone Plant. OPCo is entitled to 100% of the power generated by the Mone Plant, and is responsible for the fuel and other costs of the facility through May 2012, as extended. Following that, NPC and OPCo will be entitled to 80% and 20%, respectively, of the power of the Mone Plant, and both parties will generally be responsible for their allocable portion of the fuel and other costs of the facility.

Certain Power Agreements

I&M

The Unit Power Agreement between AEGCo and I&M, dated March 31, 1982, provides for the sale by AEGCo to I&M of all the capacity (and the energy associated therewith) available to AEGCo at the Rockport Plant. Whether or not power is available from AEGCo, I&M is obligated to pay a demand charge for the right to receive such power (and an energy charge for any associated energy taken by I&M). The agreement will continue in effect until the last of the lease terms of Unit 2 of the Rockport Plant has expired (currently December 2022) unless extended in specified circumstances.

Pursuant to an assignment between I&M and KPCo, and a unit power agreement between KPCo and AEGCo, AEGCo sells KPCo 30% of the capacity (and the energy associated therewith) available to AEGCo from both units of the Rockport Plant. KPCo has agreed to pay to AEGCo the amounts that I&M would have paid AEGCo under the terms of the Unit Power Agreement between AEGCo and I&M for such entitlement. The KPCo unit power agreement expires in December 2022.

OPCo

The Unit Power Agreement between AEGCo and OPCo dated March 15, 2007, provides for the sale by AEGCo to OPCo of all the capacity and associated unit contingent energy and ancillary services available to OPCo from the Lawrenceburg Plant. OPCo is obligated to pay a capacity charge (whether or not power is available from the Lawrenceburg Plant), and the fuel, operating and maintenance charges associated with the energy dispatched by OPCo, and to reimburse AEGCo for other costs associated with the operation and ownership of the Lawrenceburg Plant. The agreement will continue in effect until December 31, 2017 unless extended as set forth in the agreement.

OVEC

AEP and several nonaffiliated utility companies jointly own OVEC. The aggregate equity participation of AEP in OVEC is 43.47%. Until 2001, OVEC supplied from its generating capacity the power requirements of a uranium enrichment plant near Portsmouth, Ohio owned by the DOE. The sponsoring companies are entitled to receive and are obligated to pay for all OVEC capacity (approximately 2,200 MW) in proportion to their respective power participation ratios. The aggregate power participation ratio of APCo, I&M and OPCo is 43.47%. The proceeds from the sale of power by OVEC are designed to be sufficient for OVEC to meet its operating expenses and fixed costs and to provide a return on its equity capital. The Inter-Company Power Agreement, which defines the rights of the owners and sets the power participation ratio of each, was extended by the owners in 2011 from the termination date of March 2026 until June 2040. AEP and the other owners have authorized environmental investments related to their ownership interests. OVEC's Board of Directors has authorized capital expenditures totaling approximately $1.35 billion in connection with the engineering and construction of flue gas desulfurization projects and the associated scrubber waste disposal landfills at its two generating plants. OVEC has completed the financing of approximately $1.05 billion for these projects through debt issuances, including tax-advantaged debt issuances, and would expect to finance the remaining cost by issuing additional debt.

ELECTRIC TRANSMISSION AND DISTRIBUTION

General

AEP's public utility subsidiaries (other than AEGCo) own and operate transmission and distribution lines and other facilities to deliver electric power. See Item 2 – Properties for more information regarding the transmission and distribution lines. Most of the transmission and distribution services are sold, in combination with electric power, to retail customers of AEP's public utility subsidiaries in their service territories. These sales are made at rates approved by the state utility commissions of the states in which they operate, and in some instances, approved by the FERC. See Item 1 – Utility Operations – Regulation – Rates. The FERC regulates and approves the rates for wholesale transmission transactions. See Item 1 – Utility Operations – Regulation – FERC. As discussed below, some transmission services also are separately sold to non-affiliated companies.

AEP's public utility subsidiaries (other than AEGCo) hold franchises or other rights to provide electric service in various municipalities and regions in their service areas. In some cases, these franchises provide the utility with the exclusive right to provide electric service. These franchises have varying provisions and expiration dates. In general, the operating companies consider their franchises to be adequate for the conduct of their business. For a discussion of competition in the sale of power, see Item 1 – Utility Operations – Competition.

The use and the recovery of costs associated with the transmission assets of the AEP East companies, including WPCo and KGPCo, are subject to the rules, protocols and agreements in place with PJM and as approved by the FERC.

Transmission Coordination Agreement, OATT, and ERCOT Protocols

PSO, SWEPCo and AEPSC are parties to the TCA. Under the TCA, a coordinating committee is charged with the responsibility of (a) overseeing the coordinated planning of the transmission facilities of the parties to the agreement, including the performance of transmission planning studies, (b) the interaction of such subsidiaries with independent system operators and other regional bodies interested in transmission planning and (c) compliance with the terms of the OATT filed with the FERC and the rules of the FERC relating to such tariff. Pursuant to the TCA, AEPSC has responsibility for monitoring the reliability of their transmission systems and administering the OATT on behalf of the other parties to the agreement. The TCA also provides for the allocation among the parties of revenues collected for transmission and ancillary services provided under the OATT. These allocations have been determined by the FERC-approved OATT for the SPP (with respect to PSO and SWEPCo) and PUCT-approved protocols for ERCOT (with respect to TCC and TNC).

The following table shows the net (credits) or charges allocated pursuant to the TCA, SPP OATT and ERCOT protocols as described above for the years ended December 31, 2011, 2010 and 2009:

	Years Ended December 31,		
	2011	**2010**	**2009**
		(in thousands)	
PSO	$ 9,000	$ 10,500	$ 11,000
SWEPCo	(9,000)	(10,500)	(11,000)
TCC	2,100	2,100	1,700
TNC	(2,100)	(2,100)	(1,700)

Transmission Services for Non-Affiliates

In addition to providing transmission services in connection with their own power sales, AEP's public utility subsidiaries through RTOs also provide transmission services for non-affiliated companies. See Item 1 – Utility Operations – Electric Transmission and Distribution – Regional Transmission Organizations, below. Transmission of electric power by AEP's public utility subsidiaries is regulated by the FERC.

Coordination of East and West Zone Transmission

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 and AEP West companies. The System Transmission Integration Agreement functions as an umbrella agreement in addition to the TA and the TCA. AEP's System Transmission Integration Agreement contains two service schedules that govern:

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

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

Regional Transmission Organizations

The AEP East Companies are members of PJM, and SWEPCo and PSO are members of the SPP (both FERC-approved RTOs). RTOs operate, plan and control utility transmission assets in a manner designed to provide open access to such assets in a way that prevents discrimination between participants owning transmission assets and those that do not. The remaining AEP West companies (TCC and TNC) are members of ERCOT.

REGULATION

General

Except for transmission and/or retail generation sales in certain of its jurisdictions, AEP's public utility subsidiaries' retail rates and certain other matters are subject to traditional cost-based regulation by the state utility commissions. AEP's subsidiaries are also subject to regulation by the FERC under the FPA with respect to wholesale power and transmission service transactions as well as certain unbundled retail transmission rates mainly in Ohio. I&M is subject to regulation by the NRC under the Atomic Energy Act of 1954, as amended, with respect to the operation of the Cook Plant. AEP and its public utility subsidiaries are also subject to the regulatory provisions of EPACT, much of which is administered by the FERC. EPACT provides the FERC limited "backstop" transmission siting authority as well as increased utility merger oversight.

Rates

Historically, state utility commissions have established electric service rates on a cost-of-service basis, which is designed to allow a utility an opportunity to recover its cost of providing service and to earn a reasonable return on its investment used in providing that service. A utility's cost of service generally reflects its operating expenses, including operation and maintenance expense, depreciation expense and taxes. State utility commissions periodically adjust rates pursuant to a review of (a) a utility's adjusted revenues and expenses during a defined test period and (b) such utility's level of investment. Absent a legal limitation, such as a law limiting the frequency of rate changes or capping rates for a period of time, a state utility commission can review and change rates on its own initiative. Some states may initiate reviews at the request of a utility, customer, governmental or other representative of a group of customers. Such parties may, however, agree with one another not to request reviews of or changes to rates for a specified period of time.

Public utilities have traditionally financed capital investments until the new asset is placed in service. Provided the asset was found to be a prudent investment, it was then added to rate base and entitled to a return through rate recovery. Given long lead times in construction, the high costs of plant and equipment and volatile capital markets, we are actively pursuing strategies to accelerate rate recognition of investments and cash flow. AEP representatives continue to engage our state commissioners and legislators on alternative ratemaking options to reduce regulatory lag and enhance certainty in the process. These options include pre-approvals, a return on construction work in progress, rider/trackers, securitization, formula rates and the inclusion of future test-year projections into rates.

In many jurisdictions, the rates of AEP's public utility subsidiaries are generally based on the cost of providing traditional bundled electric service (i.e., generation, transmission and distribution service). In the ERCOT area of Texas, our utilities have exited the generation business and they currently charge unbundled cost-based rates for transmission and distribution service only. In Ohio, rates for electric service are unbundled for generation, transmission and distribution service. Historically, the state regulatory frameworks in the service area of the AEP System reflected specified fuel costs as part of bundled (or, more recently, unbundled) rates or incorporated fuel adjustment clauses in a utility's rates and tariffs. Fuel adjustment clauses permit periodic adjustments to fuel cost recovery from customers and therefore provide protection against exposure to fuel cost changes.

The following state-by-state analysis summarizes the regulatory environment of certain major jurisdictions in which AEP operates. Several public utility subsidiaries operate in more than one jurisdiction. See Note 3 to the consolidated financial statements, entitled Rate Matters, included in the 2011 Annual Reports, for more information regarding pending rate matters.

Indiana

I&M provides retail electric service in Indiana at bundled rates approved by the IURC, with rates set on a cost-of-service basis. Indiana provides for timely fuel and purchased power cost recovery through a fuel cost recovery mechanism.

Ohio

OPCo provides "default" retail electric service to customers at unbundled rates pursuant to the Ohio Act. OPCo exclusively provides distribution and transmission services to retail customers within their service territories at cost-based rates approved by the PUCO. Transmission services are provided at OATT rates based on rates established by the FERC. OPCo's generation/supply rates are subject to its ESP that the PUCO approved in March 2009. In December 2011, the PUCO approved a modified stipulation for a new ESP for the period January 2012 through May 2016 that includes a standard service offer (SSO) pricing for generation. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation for a new ESP and ordered a return to the 2011 ESP rates until a new rate plan is approved.

Oklahoma

PSO provides retail electric service in Oklahoma at bundled rates approved by the OCC. PSO's rates are set on a cost-of-service basis. Fuel and purchased energy costs above or below the amount included in base rates are recovered or refunded by applying a fuel adjustment factor to retail kilowatt-hour sales. The factor is generally adjusted annually and is based upon forecasted fuel and purchased energy costs. Over or under collections of fuel costs for prior periods are returned to or recovered from customers in the year following when new annual factors are established.

Texas

Retail customers in TCC's and TNC's ERCOT service area of Texas are served through non-affiliated Retail Electric Providers (REPs). TCC and TNC provide transmission and distribution service on a cost-of-service basis at rates approved by the PUCT and wholesale transmission service under tariffs approved by the FERC consistent with PUCT rules. Effective September 2009, competition in the SPP area of Texas has been delayed until certain steps defined by statute and by PUCT rule have been accomplished. As such, the PUCT continues to approve base and fuel rates for SWEPCo's Texas operations on a cost of service basis.

Virginia

APCo currently provides retail electric service in Virginia at unbundled rates approved by the Virginia SCC. Virginia generally allows for timely recovery of fuel costs through a fuel adjustment clause. Transmission services are provided at OATT rates based on rates established by the FERC. In addition to base rates and fuel cost recovery, APCo is permitted to recover a variety of costs through rate adjustment clauses.

West Virginia

APCo and WPCo provide retail electric service at bundled rates approved by the WVPSC, with rates set on a cost-of-service basis. West Virginia generally allows for timely recovery of fuel costs through an expanded net energy cost which trues-up to actual expenses.

The following table illustrates certain regulatory information with respect to the states in which the public utility subsidiaries of AEP operate:

Jurisdiction	Percentage of AEP System Retail Revenues (a)	Percentage of OSS Profits Shared with Ratepayers	AEP Utility Subsidiaries Operating in that Jurisdiction	Authorized Return on Equity (b)
Ohio	32%	No sharing included in the ESP	OPCo	(c)
Texas	12%	Not Applicable in ERCOT	TCC	9.96%
		Not Applicable in ERCOT	TNC	9.96%
		90% in SPP	SWEPCo	10.33%
Oklahoma	11%	75%	PSO	10.15%
West Virginia	11%	100%	APCo	10.00%
		100%	WPCo	10.00%
Virginia	10%	75%	APCo	10.90%
Indiana	9%	50% after certain level (d)	I&M	10.50%
Kentucky	5%	60% below and above certain level (e)	KPCo	10.50%
Louisiana	5%	50% to 100% after certain levels (f)	SWEPCo	10.57%
Arkansas	2%	50% to 100% after certain levels (g)	SWEPCo	10.25%
Michigan	2%	80%	I&M	10.20%
Tennessee	1%	Not Applicable	KGPCo	12.00%

(a) Represents the percentage of revenues from sales to retail customers from AEP utility companies operating in each state to the total AEP System revenues from sales to retail customers for the year ended December 31, 2011.

(b) Identifies the predominant authorized return on equity and may not include other, less significant, permitted recovery. Actual return on equity varies from authorized return on equity.

(c) OPCo's generation revenues are governed by its Electric Security Plan (ESP) as approved by the PUCO in March 2009. Under the ESP, authorized rate increases during the ESP period were subject to caps that limit the annual rate increases in 2009 through 2011. Some rate components and increases are exempt from the cap limitations. The ESP also provided for a fuel adjustment clause.

(d) There is an annual $37.5 million credit established for off-system sales in base rates. If the off-system sales profits exceed the amount built into base rates, I&M reimburses ratepayers 50% of the excess.

(e) There is an annual $15.3 million credit established for off-system sales in base rates. If the monthly off-system sales profits do not meet the monthly level built into base rates, ratepayers reimburse KPCo 60% of the shortfall. If the monthly off-system sales profits exceed the monthly level built into base rates, KPCo reimburses ratepayers 60% of the excess.

(f) Below $874,000, 100% is given to customers.
From $874,001 to $1,314,000, 85% is given to customers.
Above $1,314,000, 50% is given to customers.

(g) Below $758,600, 100% is given to customers.
From $758,601 to $1,167,078, 85% is given to customers.
Above $1,167,078, 50% is given to customers.

FERC

Under the FPA, the FERC regulates rates for interstate power sales at wholesale, transmission of electric power, accounting and other matters, including construction and operation of hydroelectric projects. The FERC regulations require AEP to provide open access transmission service at FERC-approved rates. The FERC also regulates unbundled transmission service to retail customers. The FERC also regulates the sale of power for resale in interstate commerce by (a) approving contracts for wholesale sales to municipal and cooperative utilities and (b) granting authority to public utilities to sell power at wholesale at market-based rates upon a showing that the seller lacks the ability to improperly influence market prices. Except for wholesale power that AEP delivers within its balancing area of the SPP, AEP has market-rate authority from the FERC, under which much of its wholesale marketing activity takes place. The FERC requires each public utility that owns or controls interstate transmission facilities to, directly or through an RTO, file an open access network and point-to-point transmission tariff that offers services comparable to the utility's own uses of its transmission system. The FERC also requires all transmitting utilities, directly or through an RTO, to establish an OASIS, which electronically posts transmission information such as available capacity and prices, and requires utilities to comply with Standards of Conduct that prohibit utilities' transmission employees from providing non-public transmission information to the utility's marketing employees.

The FERC oversees RTOs, entities created to operate, plan and control utility transmission assets. Order 2000 also prescribes certain characteristics and functions of acceptable RTO proposals. The AEP East Companies are members of PJM. SWEPCo and PSO are members of SPP.

The FERC has jurisdiction over the issuances of securities of most of our public utility subsidiaries, the acquisition of securities of utilities, the acquisition or sale of certain utility assets and mergers with another electric utility or holding company. In addition, both the FERC and state regulators are permitted to review the books and records of any company within a holding company system. EPACT gives the FERC limited "backstop" transmission siting authority as well as increased utility merger oversight.

Competition

Under current Ohio legislation, electric generation is sold in a competitive market in Ohio, and our native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers are targeting retail customers by offering alternative generation service. A growing number of OPCo's commercial retail customers have switched to alternative generation providers while additional Ohio customers have provided notice of their intent to switch. Currently, there are no limitations on the obligation of OPCo to provide below cost capacity rate pricing to alternative suppliers to support customers switching in Ohio. These evolving market conditions will continue to impact OPCo's results of operations. A retail supply subsidiary operates as a competitive retail electric service provider in Ohio.

The public utility subsidiaries of AEP, like the electric industry generally, face competition in the sale of available power on a wholesale basis, primarily to other public utilities and power marketers. The Energy Policy Act of 1992 was designed, among other things, to foster competition in the wholesale market by creating a generation market with fewer barriers to entry and mandating that all generators have equal access to transmission services. As a result, there are more generators able to participate in this market. The principal factors in competing for wholesale sales are price (including fuel costs), availability of capacity and power and reliability of service.

AEP's public utility subsidiaries also compete with self-generation and with distributors of other energy sources, such as natural gas, fuel oil and coal, within their service areas. The primary factors in such competition are price, reliability of service and the capability of customers to utilize sources of energy other than electric power. With respect to competing generators and self-generation, the public utility subsidiaries of AEP believe that they generally maintain a favorable competitive position. With respect to alternative sources of energy, the public utility subsidiaries of AEP believe that the reliability of their service and the limited ability of customers to substitute other cost-effective sources for electric power place them in a favorable competitive position, even though their prices may be higher than the costs of some other sources of energy.

Significant changes in the global economy have led to increased price competition for industrial customers in the United States, including those served by the AEP System. Some of these industrial customers have requested price reductions from their suppliers of electric power. In addition, industrial customers that are downsizing or reorganizing often close a facility based upon its costs, which may include, among other things, the cost of electric power. The public utility subsidiaries of AEP cooperate with such customers to meet their business needs through, for example, providing various off-peak or interruptible supply options pursuant to tariffs filed with, and approved by, the various state commissions. Occasionally, these rates are negotiated with the customer, and then filed with the state commissions for approval.

Seasonality

The sale of electric power is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. The pattern of this fluctuation may change due to the nature and location of AEP's facilities and the terms of power sale contracts into which AEP enters. In addition, AEP has historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish AEP's results of operations and may impact its financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations.

TRANSMISSION OPERATIONS

Wholly-owned Entities

AEP Transco, a subsidiary of AEP, has seven wholly-owned transmission companies, geographically aligned with our existing operating companies. These transmission companies will develop and own new transmission assets that are physically connected to AEP's system. The transmission companies have been approved in Indiana, Michigan, Ohio and Oklahoma. Applications for approval of the transmission companies have been filed with the APSC, the KPSC, the LPSC, the Virginia SCC and the WVPSC and are pending approval.

AEP Transco rates have been approved and will be regulated by the FERC, and are included in PJM's and SPP's OATT. AEPSC and other AEP subsidiaries provide services to the transmission companies through service agreements. Therefore, the transmission companies do not have any employees.

All of the transmission companies' capital needs are provided by Parent, AEP Transco and/or the AEP Utility Money Pool. The Utility Money Pool is used to meet the short-term borrowing needs of AEP regulated utility subsidiaries. The Utility Money Pool operates in accordance with the terms and conditions approved in regulatory orders. For the consolidated entities within our Transmission Operations segment, we forecast approximately $350 million, excluding AFUDC, of construction expenditures for 2012.

Joint Venture Initiatives

We have established joint ventures with other incumbent electric utility companies for the purpose of developing, building and owning Extra High Voltage (EHV) transmission lines to improve reliability and market efficiency and to access remote generation sources in North America. Our joint ventures are invested in EHV projects at various stages of regulatory and RTO approval.

Our most significant joint venture, Electric Transmission Texas, LLC (ETT), was established to construct, fund, own and operate electric transmission assets within ERCOT, including transmission projects in the Competitive Renewable Energy Zone (CREZ). The PUCT has awarded approximately $1.5 billion of total CREZ investment to ETT.

Business services for the joint ventures are provided by AEPSC and the joint venture partner entity. Therefore, the joint ventures do not have any employees. For the equity investments within our Transmission Operations segment, we forecast approximately $116 million of AEP equity contributions in 2012 to support construction expenditures and the payment of operating expenses.

AEP RIVER OPERATIONS

Our AEP River Operations Segment transports coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi rivers. Almost all of our customers are nonaffiliated third parties who obtain the transport of coal and dry bulk commodities for various uses. We charge these customers market rates for the purpose of making a profit. Depending on market conditions and other factors, including barge availability, we permit AEP utility subsidiary affiliates to use certain of our equipment at rates that reflect our cost. Our affiliated utility customers procure the transport of coal for use as fuel in their respective generating plants. AEP River Operations includes approximately 2,600 barges, 45 towboats and 25 harbor boats that we own or lease. These assets are separate from the barges and towboats dedicated exclusively to transporting coal for use as fuel in our own generating facilities discussed under the prior segment. See Item 1 – Utility Operations – Electric Generation – Fuel Supply – Coal and Lignite.

Competition within the barging industry for major commodity contracts is intense, with a number of companies offering transportation services in the waterways we serve. We compete with other carriers primarily on the basis of commodity shipping rates, but also with respect to customer service, available routes, value-added services (including scheduling convenience and flexibility). The industry continues to experience consolidation. The resulting companies increasingly offer the widespread geographic reach necessary to support major national customers. Demand for barging services can be seasonal, particularly with respect to the movement of harvested agricultural commodities (beginning in the late summer and extending through the fall). Cold winter weather, water levels and inefficient older river locks operated by others may also limit our operations when certain of the waterways we serve are closed.

Our transportation operations are subject to regulation by the U.S. Coast Guard, federal laws, state laws and certain international conventions. Legislation has been proposed that could make our towboats subject to inspection by the U.S. Coast Guard.

GENERATION AND MARKETING

Our Generation and Marketing Segment consists of nonutility generating assets and a competitive power supply and energy trading and marketing business. We enter into short and long-term transactions to buy or sell capacity, energy and ancillary services primarily in the ERCOT market, and to a lesser extent Ohio in PJM and MISO. As of December 31, 2011, the assets utilized in this segment included approximately 310 MW of company-owned domestic wind power facilities, 177 MW of domestic wind power from long-term purchase power agreements and 377 MW of coal-fired capacity which was obtained through an agreement effective through 2027 that transfers TNC's interest in the Oklaunion power station to AEP Energy Partners, Inc. The power obtained from the Oklaunion power station is marketed and sold in ERCOT. We are regulated by the PUCT for transactions inside ERCOT and by the FERC for transactions outside of ERCOT. While peak load in ERCOT typically occurs in the summer, we do not necessarily expect seasonal variation in our operations. In 2010, we started operations of a retail energy business in the State of Ohio to sell competitive power supply to residential, commercial and industrial customers in the deregulated areas within or near AEP's traditional utility service areas.

EXECUTIVE OFFICERS OF AEP as of February 28, 2012

The following persons are executive officers of AEP. Their ages are given as of February 1, 2012. The officers are appointed annually for a one-year term by the board of directors of AEP.

Nicholas K. Akins
President and Chief Executive Officer
Age 51
Chief Executive Officer since November 2011 and President since January 2011. Was Executive Vice President from August 2006 to December 2010.

Lisa M. Barton
Executive Vice President – Transmission
Age 46
Executive Vice President-Transmission of AEPSC since August 2011. Was Senior Vice President-Transmission Strategy and Business Development of AEPSC from November 2010 to July 2011, Vice President-Transmission Strategy and Business Development of AEPSC from October 2007 to November 2010, Managing Director, Transmission of AEPSC from September 2007 to October 2007 and Director of Transmission Planning of AEPSC from December 2006 to September 2007.

David M. Feinberg
Senior Vice President, General Counsel and Secretary
Age 42
Senior Vice President, General Counsel and Secretary since January 2012. Senior Vice President and General Counsel of AEPSC from May 2011. Previously served as Vice President, General Counsel and Secretary of Allegheny Energy, Inc. from 2006 to 2011.

Mark C. McCullough
Executive Vice President – Generation
Age 52
Executive Vice President-Generation of AEPSC since January 2011. Was Senior Vice President-Fossil & Hydro Generation of AEPSC from February 2008 to December 2010 and Vice President-Baseload Generation of AEPSC from June 2005 to February 2008.

Robert P. Powers
Executive Vice President and Chief Operating Officer
Age 57
Executive Vice President and Chief Operating Officer since November 2011. Was President-Utility Group from April 2009 to November 2011, President-AEP Utilities from January 2008 to April 2009 and Executive Vice President from 2004 to 2008.

Brian X. Tierney
Executive Vice President and Chief Financial Officer
Age 44
Executive Vice President and Chief Financial Officer since October 2009. Was Executive Vice President-AEP Utilities East of AEPSC from January 2008 to October 2009 and Senior Vice President-Commercial Operations of AEPSC from 2005 to January 2008.

Dennis E. Welch
Executive Vice President and Chief Administrative Officer
Age 60
Executive Vice President and Chief Administrative Officer since October 2011. Was Executive Vice President from January 2008 to September 2011 and Senior Vice President from August 2005 to December 2007.

ITEM 1A. RISK FACTORS

GENERAL RISKS OF OUR REGULATED OPERATIONS

The regulatory environment in Ohio has recently become unpredictable and increasingly uncertain. – Affecting AEP and OPCo

For some time, our retail sales of electricity in Ohio have accounted for approximately 30% of our utilities segment revenue. Due to a number of reasons, including commission turnover and a renewed emphasis on deregulation, the regulatory environment in Ohio has become increasingly unpredictable. The current regulatory environment in Ohio could result in an extended period of uncertainty and cause our financial performance in Ohio to be volatile and difficult to project.

We may not be able to recover the costs of our substantial planned investment in capital improvements and additions. – Affecting each Registrant

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades and retrofits, construction and/or acquisition of additional generation units and transmission facilities, modernizing existing infrastructure as well as other initiatives. Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. If these regulatory commissions do not approve adjustments to the rates we charge, we would not be able to recover the costs associated with our planned extensive investment. This would cause our financial results to be diminished. While we may seek to limit the impact of any denied recovery by attempting to reduce the scope of our capital investment, there can be no assurance as to the effectiveness of any such mitigation efforts, particularly with respect to previously incurred costs and commitments.

Rate and other recovery in Ohio for distribution service may not provide full recovery of costs. – Affecting AEP and OPCo

In February 2011, OPCo filed with the PUCO for an annual increase in distribution rates. In December 2011, a stipulation agreement was approved by the PUCO providing recovery of certain distribution regulatory assets. Due to a February 2012 PUCO ESP rehearing order, which rejected the ESP modified stipulation, collection of the Distribution Investment Rider terminated. If OPCo is not ultimately permitted to fully recover its deferrals and costs, it would reduce future net income and cash flows and impact financial condition.

Rate recovery in Ohio for generation service may not provide full recovery of costs. – Affecting AEP and OPCo

In January 2011, OPCo filed an application with the PUCO to approve a new ESP that included a standard service offer pricing for generation. In December 2011, a modified stipulation agreement was approved by the PUCO which involved various issues pending before the PUCO, including generation rates and the recovery of fuel costs. In February 2012, the PUCO issued an entry on rehearing which rejected the ESP approved modified stipulation and ordered a return to the 2011 ESP rates until a new rate plan is approved. Under the February 2012 rehearing order, OPCo has 30 days to notify the PUCO whether it plans to modify or withdraw its original application as filed in January 2011. Management is currently evaluating its options and the potential financial and operational impacts on OPCo. If OPCo is not ultimately permitted to fully recover its costs, it would reduce future net income and cash flows and impact financial condition.

Rate recovery approved in Ohio may have to be returned and/or may not provide full recovery of costs. – Affecting AEP and OPCo

The PUCO issued an order in March 2009 that modified and approved the Electric Security Plan (ESP) which established rates through 2011. The ESP order generally authorized rate increases during the ESP period, subject to caps that limit the rate increases, and also provides a fuel adjustment clause for the three-year period of the ESP. The recovery under the fuel adjustment clause includes deferrals associated with the Ormet interim arrangement and is subject to the PUCO's ultimate decision regarding the Ormet interim arrangement deferrals plus related carrying charges. In July 2011, OPCo filed its 2010 SEET filing with the PUCO. If the PUCO and/or the Supreme Court of Ohio reverses all or part of the rate recovery or if deferred fuel costs are not fully recovered for other reasons, it could reduce future net income and cash flows and impact financial condition.

Oklahoma may require us to refund fuel costs that we have collected. – Affecting PSO

In July 2009, the OCC initiated a proceeding to review PSO's fuel and purchased power adjustment clause for the calendar year 2008 and also initiated a prudence review of the related costs. In March 2010, the Oklahoma Attorney General and an intervenor recommended the fuel clause adjustment rider be amended to decrease the shareholder's portion of off-system sales margins from 25% to 10%. That intervenor also recommended that the OCC conduct a comprehensive review of all affiliate fuel transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEP Energy Partners was filed. Included in this testimony were unquantified refund recommendations relating to re-pricing of contract transactions. If the OCC were to issue an unfavorable decision, it would reduce future net income and cash flows and impact financial condition.

We may not recover costs incurred to begin construction on projects that are canceled. – Affecting each Registrant

Our business plan for the construction of new projects involves a number of risks, including construction delays, nonperformance by equipment and other third party suppliers, and increases in equipment and labor costs. To limit the risks of these construction projects, we enter into equipment purchase orders and construction contracts and incur engineering and design service costs in advance of receiving necessary regulatory approvals and/or siting or environmental permits. If any of these projects is canceled for any reason, including our failure to receive necessary regulatory approvals and/or siting or environmental permits, we could incur significant cancellation penalties under the equipment purchase orders and construction contracts. In addition, if we have recorded any construction work or investments as a regulatory asset we may need to impair that asset in the event the project is canceled.

Rate regulation may delay or deny full recovery of capital improvements, additions and other costs. – Affecting each Registrant

Our public utility subsidiaries currently provide service at rates approved by one or more regulatory commissions. These rates are generally regulated based on an analysis of the applicable utility's expenses incurred in a test year. Thus, commission-approved rates may or may not match a utility's expenses at any given time. There may also be a delay between the timing of when these costs are incurred and when these costs are recovered. Traditionally, we have financed capital investments and improvements until the new asset was placed in service. Provided the asset was found to be a prudent investment, the asset was then added to rate base and entitled to a return through rate recovery. Long lead times in construction, the high costs of plant and equipment and volatile capital markets have heightened the risks involved in our capital investments and improvements. While we are actively pursuing strategies to accelerate rate recognition of investments and cash flow, including pre-approvals, a return on construction work in progress, rider/trackers, formula rates and the inclusion of future test-year projections into rates, there can be no assurance that these will be adopted, that the applicable regulatory commission will judge all of our costs to have been prudently incurred or that the regulatory process in which rates are determined will be done in a timely manner.

Certain of our revenues and results of operations are subject to risks that are beyond our control. – Affecting each Registrant

Our operations are structured to comply with all applicable federal and state laws and regulations and we take measures to minimize the risk of significant disruptions. Material disruptions at one or more of our operational facilities, however, could negatively impact our revenues, operating and capital expenditures and results of operations. Such events may also create additional risks related to the supply and/or cost of equipment and materials. We could experience unexpected but significant interruption due to several events, including, but not limited to:

- Major facility or equipment failure.
- An environmental event such as a serious spill or release.
- Fires, floods, droughts, earthquakes, hurricanes or other natural disasters.
- Wars, terrorist acts (including cyber-terrorism) or threats and other catastrophic events.
- Significant health impairments or disease events.
- Other serious operational problems.

We are exposed to nuclear generation risk. – Affecting AEP and I&M

Through I&M, we own the Cook Plant. It consists of two nuclear generating units for a rated capacity of 2,191 MW, or 8-9% of the electricity generated by the AEP System. We are, therefore, subject to the risks of nuclear generation, which include the following:

- The potential harmful effects on the environment and human health resulting from the operation of nuclear facilities and the storage, handling and disposal of radioactive materials such as spent nuclear fuel.
- Limitations on the amounts and types of insurance commercially available to cover losses that might arise in connection with our nuclear operations.
- Uncertainties with respect to contingencies and assessment amounts if insurance coverage is inadequate (federal law requires owners of nuclear units to purchase the maximum available amount of nuclear liability insurance and potentially contribute to the losses of others).
- Uncertainties with respect to the technological and financial aspects of decommissioning nuclear plants at the end of their licensed lives.

There can be no assurance that I&M's preparations or risk mitigation measures will be adequate if and when these risks are triggered.

The NRC has broad authority under federal law to impose licensing and safety-related requirements for the operation of nuclear generation facilities. In the event of non-compliance, the NRC has the authority to impose fines or shut down a unit, or both, depending upon its assessment of the severity of the situation, until compliance is achieved. Revised safety requirements promulgated by the NRC could necessitate substantial capital expenditures at nuclear plants such as ours. In addition, although we have no reason to anticipate a serious nuclear incident at our plants, if an incident did occur, it could harm our results of operations or financial condition. A major incident at a nuclear facility anywhere in the world could cause the NRC to limit or prohibit the operation or licensing of any domestic nuclear unit. Moreover, a major incident at any nuclear facility in the U.S. could require us to make material contributory payments.

Costs associated with the operation (including fuel), maintenance and retirement of nuclear plants continue to be more significant and less predictable than costs associated with other sources of generation, in large part due to changing regulatory requirements and safety standards, availability of nuclear waste disposal facilities and experience gained in the operation of nuclear facilities. Costs also may include replacement power, any unamortized investment at the end of the useful life of the Cook Plant (whether scheduled or premature), the carrying costs of that investment and retirement costs. Our ability to obtain adequate and timely recovery of costs associated with the Cook Plant is not assured.

As a result of the nuclear plant situation in Japan following a March 2011 earthquake, the NRC has initiated a review of safety procedures and requirements for nuclear generating facilities. This review could increase procedures and testing requirements, require physical modifications to the plant and increase future operating costs at the Cook Plant. In addition to the review by the NRC, Congress could consider legislation tightening oversight of nuclear generating facilities. We are unable to predict the impact of potential future regulation of nuclear facilities.

The different regional power markets in which we compete or will compete in the future have changing market and transmission structures, which could affect our performance in these regions. – Affecting each Registrant

Our results are likely to be affected by differences in the market and transmission structures in various regional power markets. The rules governing the various regional power markets, including SPP and PJM, may also change from time to time which could affect our costs or revenues. Because the manner in which RTOs will evolve remains unclear, we are unable to assess fully the impact that changes in these power markets may have on our business.

The amount we charged third parties for using our transmission facilities is subject to refund. – Affecting each Registrant

In July 2003, the FERC issued an order directing PJM and MISO to make compliance filings for their respective tariffs to eliminate the transaction-based charges for through and out (T&O) transmission service on transactions where the energy is delivered within those RTOs. To mitigate the impact of lost T&O revenues, the FERC approved temporary replacement seams elimination cost allocation (SECA) transition rates beginning in December 2004 and extending through March 2006. Because intervenors objected to this decision, the SECA fees we collected ($220 million) are subject to refund. Some claims for refund have been settled, and we have recorded a provision for estimated settlement refunds for the remaining unsettled $108 million of gross SECA revenues collected. Any payments in excess of the reserve balance could reduce future net income and cash flows and impact financial condition.

We could be subject to higher costs and/or penalties related to mandatory reliability standards. – Affecting each Registrant

As a result of EPACT, owners and operators of the bulk power transmission system are subject to mandatory reliability standards promulgated by the North American Electric Reliability Corporation and enforced by the FERC. These standards, which previously were being applied on a voluntary basis, became mandatory in June 2007. The standards are based on the functions that need to be performed to ensure the bulk power system operates reliably and are guided by reliability and market interface principles. Compliance with new reliability standards may subject us to higher operating costs and/or increased capital expenditures. While we expect to recover costs and expenditures from customers through regulated rates, there can be no assurance that the applicable commissions will approve full recovery in a timely manner. If we were found not to be in compliance with the mandatory reliability standards, we could be subject to sanctions, including substantial monetary penalties, which likely would not be recoverable from customers through regulated rates.

At times, demand for power could exceed our supply capacity. – Affecting each Registrant

We are currently obligated to supply power in parts of eleven states. From time to time, because of unforeseen circumstances, the demand for power required to meet these obligations could exceed our available generation capacity. If this occurs, we would have to buy power from the market. This would increase the pressure on our short-term debt financing capacity in times of tight liquidity. We may not always have the ability to pass these costs on to our customers, and the time lag between incurring costs and recovery can be long. Since these situations most often occur during periods of peak demand, it is possible that the market price for power at that time would be very high. Even if a supply shortage were brief, we could suffer substantial losses that could reduce our results of operations.

RISKS RELATED TO MARKET, ECONOMIC OR FINANCIAL VOLATILITY AND OTHER RISKS

Our financial performance may be adversely affected if we are unable to successfully operate our facilities or perform certain corporate functions. – Affecting each Registrant

Our performance is highly dependent on the successful operation of our generation, transmission and distribution facilities. Operating these facilities involves many risks, including:

- Operator error and breakdown or failure of equipment or processes.
- Operating limitations that may be imposed by environmental or other regulatory requirements.
- Labor disputes.
- Compliance with mandatory reliability standards, including mandatory cyber security standards.
- Information technology failure that impairs our information technology infrastructure or disrupts normal business operations.
- Information technology failure that affects our ability to access customer information or causes us to lose confidential or proprietary data that materially and adversely affects our reputation or exposes us to legal claims.
- Fuel or water supply interruptions caused by transportation constraints, adverse weather such as drought, non-performance by our suppliers and other factors.
- Catastrophic events such as fires, earthquakes, explosions, hurricanes, terrorism (including cyber-terrorism), floods or other similar occurrences.

We may be subject to disruptions or failures in our information technology systems and network infrastructures that could have a material adverse effect on us. – Affecting each Registrant

We maintain and rely extensively on information technology systems and network infrastructures for the effective operation of our business. We also hold large amounts of data in various data center facilities which our business depends upon. A disruption, infiltration or failure of our information technology systems or any of our data centers as a result of software or hardware malfunctions, computer viruses, cyber attacks, employee theft or misuse, power disruptions, natural disasters or accidents could cause breaches of data security and loss of critical data, which in turn could materially adversely affect our business. Our security procedures, such as virus protection software, cyber security and our business continuity planning, such as our disaster recovery policies and back-up systems, may not be adequate or implemented properly to fully address the adverse effect of such events, which could adversely impact our operations. In addition, our business could be adversely affected to the extent we do not make the appropriate level of investment in our technology systems as our technology systems become out-of-date or obsolete.

If we are unable to access capital markets on reasonable terms, it could have an adverse impact on our net income, cash flows and financial condition. – Affecting each Registrant

We rely on access to capital markets as a significant source of liquidity for capital requirements not satisfied by operating cash flows. Volatility and reduced liquidity in the financial markets could affect our ability to raise capital and fund our capital needs, including construction costs and refinancing maturing indebtedness. In addition, if capital is available only on less than reasonable terms or to borrowers whose creditworthiness is better than ours, capital costs could increase materially. Restricted access to capital markets and/or increased borrowing costs could have an adverse impact on net income, cash flows and financial condition.

Downgrades in our credit ratings could negatively affect our ability to access capital and/or to operate our power trading businesses. – Affecting each Registrant

The credit ratings agencies periodically review our capital structure and the quality and stability of our earnings. Any negative ratings actions could constrain the capital available to us and could limit our access to funding for our operations. Our business is capital intensive, and we are dependent upon our ability to access capital at rates and on terms we determine to be attractive. In periods of market turmoil, access to capital is difficult for all borrowers. If our ability to access capital becomes significantly constrained, our interest costs will likely increase and our financial condition could be harmed and future results of operations could be adversely affected.

Our power trading business relies on the investment grade ratings of our individual public utility subsidiaries' senior unsecured long-term debt or on the investment grade ratings of AEP parent. Most of our counterparties require the creditworthiness of an investment grade entity to stand behind transactions. If those ratings were to decline below investment grade, our ability to operate our power trading business profitably would be diminished because we would likely have to deposit cash or cash-related instruments which would reduce our profits.

Our pension plan could require additional significant contributions. – Affecting each Registrant

The performance of the capital markets affects the value of the assets that are held in trust to satisfy future obligations under our defined benefit pension plan. The volatility of the capital markets in the past years has affected the market value of these assets. Also, a decline in interest rates on corporate bonds in 2011 has impacted the benchmark discount rate in a way that results in a higher calculated pension liability. Accordingly, our future required contributions to fund obligations under our defined benefit plan could be more than expected.

AEP has no income or cash flow apart from dividends paid or other obligations due it from its subsidiaries. – Affecting AEP

AEP is a holding company and has no operations of its own. Its ability to meet its financial obligations associated with its indebtedness and to pay dividends on its common stock is primarily dependent on the earnings and cash flows of its operating subsidiaries, primarily its regulated utilities, and the ability of its subsidiaries to pay dividends to, or repay loans from, AEP. Its subsidiaries are separate and distinct legal entities that have no obligation (apart from loans from AEP) to provide AEP with funds for its payment obligations, whether by dividends, distributions or other payments. Payments to AEP by its subsidiaries are also contingent upon their earnings and business considerations. In addition, any payment of dividends, distributions or advances by the utility subsidiaries to AEP could be subject to regulatory restrictions. AEP indebtedness and common stock dividends are structurally subordinated to all subsidiary indebtedness and preferred stock obligations.

Our operating results may fluctuate on a seasonal or quarterly basis and with general economic and weather conditions. – Affecting each Registrant

Electric power generation is generally a seasonal business. In many parts of the country, demand for power peaks during the hot summer months, with market prices also peaking at that time. In other areas, power demand peaks during the winter. As a result, our overall operating results in the future may fluctuate substantially on a seasonal basis. The pattern of this fluctuation may change depending on the terms of power sale contracts that we enter into. In addition, we have historically sold less power, and consequently earned less income, when weather conditions are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition. Conversely, unusually extreme weather conditions could increase AEP's results of operations in a manner that would not likely be sustainable.

Further, deteriorating economic conditions generally result in reduced consumption by our customers, particularly industrial customers who may curtail operations or cease production entirely, while an expanding economic environment generally results in increased revenues. As a result, our overall operating results in the future may fluctuate on the basis of prevailing economic conditions.

Failure to attract and retain an appropriately qualified workforce could harm our results of operations. – Affecting each Registrant

Certain events, such as an aging workforce without appropriate replacements, mismatch of skillset or complement to future needs, or unavailability of contract resources may lead to operating challenges and increased costs. The challenges include lack of resources, loss of knowledge and a lengthy time period associated with skill development. In this case, costs, including costs for contractors to replace employees, productivity costs and safety costs, may rise. Failure to hire and adequately train replacement employees, including the transfer of significant internal historical knowledge and expertise to the new employees, or the future availability and cost of contract labor may adversely affect the ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be negatively affected.

Parties we have engaged to provide construction materials or services may fail to perform their obligations, which could harm our results of operations. – Affecting each Registrant

Our business plan calls for extensive investment in capital improvements and additions, including the installation of environmental upgrades, construction of additional generation units and transmission facilities as well as other initiatives. We are exposed to the risk of substantial price increases in the costs of materials used in construction. We have engaged numerous contractors and entered into a large number of agreements to acquire the necessary materials and/or obtain the required construction related services. As a result, we are also exposed to the risk that these contractors and other counterparties could breach their obligations to us. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative arrangements at then-current market prices that may exceed our contractual prices and almost certainly cause delays in that and related projects. Although our agreements are designed to mitigate the consequences of a potential default by the counterparty, our actual exposure may be greater than these mitigation provisions. This would cause our financial results to be diminished, and we might incur losses or delays in completing construction.

Changes in commodity prices and the costs of transport may increase our cost of producing power or decrease the amount we receive from selling power, harming our financial performance. – Affecting each Registrant

We are exposed to changes in the price and availability of coal and the price and availability to transport coal because most of our generating capacity is coal-fired. We have contracts of varying durations for the supply of coal for most of our existing generation capacity, but as these contracts end or otherwise are not honored, we may not be able to purchase coal on terms as favorable as the current contracts. Similarly, we are exposed to changes in the price and availability of emission allowances. We use emission allowances based on the amount of coal we use as fuel and the reductions achieved through emission controls and other measures. As long as current environmental programs remain in effect, we have sufficient emission allowances to cover nearly all of our projected needs for the next two years as well as a majority of our needs beyond that timeframe. If the Federal EPA's replacement rule to reduce interstate transport were to take effect, additional costs may be incurred to acquire supplemental allowances for compliance or to achieve further reductions in emissions. If and when we obtain additional allowances those purchases may not be on as favorable terms as those currently obtained. Our risks relative to the price and availability to transport coal include the volatility of the price of diesel which is the primary fuel used in transporting coal by barge.

We also own natural gas-fired facilities which increases our exposure to market prices of natural gas. Natural gas prices tend to be more volatile than prices for other fuel sources. Our ability to make off-system sales at a profit is highly dependent on the price of natural gas. As the price of natural gas falls, other market participants that utilize natural gas-fired generation will be able to offer electricity at increasingly competitive prices relative to our off-system sales prices, so the margins we realize from sales will be lower and, on occasion, we may need to curtail operation of marginal plants. The availability of shale natural gas and issues related to its accessibility may have a long-term material effect on the price of natural gas.

Prices for coal, natural gas and emission allowances have shown material upward and downward swings in the recent past. Changes in the cost of coal, emission allowances or natural gas and changes in the relationship between such costs and the market prices of power will affect our financial results. Since the prices we obtain for power may not change at the same rate as the change in coal, emission allowances or natural gas costs, we may be unable to pass on the changes in costs to our customers.

In addition, actual power prices and fuel costs will differ from those assumed in financial projections used to value our trading and marketing transactions, and those differences may be material. As a result, our financial results may be diminished in the future as those transactions are marked to market.

RISKS RELATING TO STATE RESTRUCTURING

We are unable to fully predict the effects of legal separation in Ohio and becoming subject to market forces. – Affecting AEP and OPCo

In January 2012, the PUCO approved the corporate separation plan of OPCo's generation assets to complete the transition to a fully competitive generation market by June 2015. The corporate separation plan also would require approval by the FERC under provisions of the Federal Power Act. In February 2012, as part of the PUCO's entry on rehearing which rejected the ESP approved modified stipulation, the PUCO revoked its approval of OPCo's corporate separation plan. Also, in February 2012, prior to the PUCO revoking OPCo's corporate separation plan, an application was filed with the FERC seeking approval, among other things, to transfer OPCo's generation assets to APCo, KPCo and a nonregulated AEP subsidiary. If we can obtain regulatory approvals, our results of operations related to Ohio generation would be determined by our ability to sell power at a profit at rates determined by the prevailing market. As a result of the February 2012 ESP rehearing order, we are in the process of withdrawing the PUCO and FERC applications. We intend to file new FERC and PUCO applications related to corporate separation. We can give no assurance that the PUCO or the FERC will not impose material adverse terms as a condition to approving our legal separation. Additionally, certain of our generation units may no longer be cost effective and may be retired prior to the end of their anticipated useful life. Because such generation assets are no longer subject to cost recovery regulation, this could result in material impairments.

We are unable to predict the consequences of terminating the Interconnection Agreement and breaking up the AEP Power Pool. – Affecting AEP, APCo, I&M and OPCo

The proposed corporate separation plans of OPCo's generation assets will require us to either terminate or substantially alter the Interconnection Agreement. The Interconnection Agreement establishes the AEP Power Pool which permits AEP East companies to share costs and benefits associated with their generating plants on a cost basis. 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 bi-lateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. If the AEP Power Pool is terminated without any subsequent agreements between some or all of the parties, surplus members will no longer automatically sell to deficit members, and they may not be able to otherwise sell that surplus in amounts or at rates equal to what they obtained under the Interconnection Agreement. Conversely, deficit members will no longer automatically purchase from surplus members, and they may not be able to otherwise purchase in amounts or at rates equal to what they obtained under the Interconnection Agreement. The possible loss of these sales by the surplus members and the potential increase in costs for the deficit members could reduce future net income and cash flows. We have filed with the FERC seeking approval of the termination of the Interconnection Agreement, the implementation of a power cost sharing agreement between APCo, I&M and KPCo, and to transfer certain generation assets from OPCo to APCo, KPCo and a nonregulated AEP subsidiary. As a result of the February 2012 ESP rehearing order, we are in the process of withdrawing the PUCO and FERC applications. We intend to file new FERC and PUCO applications related to corporate separation. We can give no assurance that the FERC or other state utility commissions will not impose material adverse terms as a condition to approving these arrangements and the termination of the Interconnection Agreement.

Customers are choosing alternative electric generation service providers, as allowed by Ohio law and regulation. – Affecting AEP and OPCo

Under current Ohio law, electric generation is sold in a competitive market in Ohio and native load customers in Ohio have the ability to switch to alternative suppliers for their electric generation service. Competitive power suppliers are targeting retail customers by offering alternative generation service. A growing number of commercial retail customers have switched to alternative generation providers while additional Ohio customers have provided notice of their intent to switch. In 2011, we lost approximately 10% of our Ohio load due to customer switching. Currently, there are no limitations on the obligation to provide below cost capacity rate pricing to alternative suppliers to support customers switching in Ohio. These evolving market conditions will continue to impact our results of operations.

Collection of our revenues in Texas is concentrated in a limited number of REPs. – Affecting AEP

Our revenues from the distribution of electricity in the ERCOT area of Texas are collected from REPs that supply the electricity we distribute to their customers. Currently, we do business with approximately one hundred REPs. In 2011, TCC's largest customer accounted for 22% of its operating revenue and its second largest customer accounted for 12% of its operating revenue; TNC's largest customer (a non-utility affiliate) accounted for 28% of its operating revenues and its second largest customer accounted for 15% of its operating revenues. Adverse economic conditions, structural problems in the Texas market or financial difficulties of one or more REPs could impair the ability of these REPs to pay for our services or could cause them to delay such payments. We depend on these REPs for timely remittance of payments. Any delay or default in payment could adversely affect the timing and receipt of our cash flows and thereby have an adverse effect on our liquidity.

RISKS RELATED TO OWNING AND OPERATING GENERATION ASSETS AND SELLING POWER

Our costs of compliance with existing environmental laws are significant. – Affecting each Registrant

Our operations are subject to extensive federal, state and local environmental statutes, rules and regulations relating to air quality, water quality, waste management, natural resources and health and safety. Approximately 90% of the electricity generated by the AEP System is produced by the combustion of fossil fuels. Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are subject to increased regulations, controls and mitigation expenses. Compliance with these legal requirements requires us to commit significant capital toward environmental monitoring, installation of pollution control equipment, emission fees and permits at all of our facilities and could cause us to retire generating capacity prior to the end of its estimated useful life. These expenditures have been significant in the past and we expect that they will continue to be significant in order to comply with the current and proposed regulations. Costs of compliance with environmental regulations could adversely affect our net income and financial position, especially if emission and/or discharge limits are tightened, more extensive permitting requirements are imposed, additional substances become regulated and the number and types of assets we operate increase. If we retire generating plants prior to the end of their estimated useful life, there can be no assurance that we will recover the remaining costs associated with such plants. While we expect to recover our expenditures for pollution control technologies, replacement generation and associated operating costs from customers through regulated rates (in regulated jurisdictions) or market prices, without such recovery those costs could reduce our future net income and cash flows and possibly harm our financial condition.

Regulation of CO_2 emissions, either through legislation or by the Federal EPA, could materially increase costs to us and our customers or cause some of our electric generating units to be uneconomical to operate or maintain. – Affecting each Registrant

The U.S. Congress has not taken any significant steps toward enacting legislation to control CO_2 emissions since 2009. In December 2009, the Federal EPA issued a final endangerment finding under the CAA regarding emissions from motor vehicles. The Federal EPA also finalized CO_2 emission standards for new motor vehicles, and issued a rule that implements a permitting program for new and modified stationary sources of CO_2 emissions in a phased manner through 2014. Several groups have filed challenges to the endangerment finding and the Federal EPA's subsequent rulemakings. The Federal EPA has announced its intent to propose a CO_2 emissions standard for new power generation sources during the next year. Management believes some policy approaches being discussed would have significant and widespread negative consequences for the national economy and major U.S. Industrial enterprises, including us and our customers.

If CO_2 and other emission standards are imposed, the standards could require significant increases in capital expenditures and operating costs which would impact the ultimate retirement of older, less-efficient, coal-fired units. While we expect that costs of complying with new CO_2 and other GHG emission standards will be treated like all other reasonable costs of serving customers and should be recoverable from customers as costs of doing business, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition.

Courts adjudicating nuisance and other similar claims against us may order us to pay damages or to limit or reduce our CO_2 emissions. – Affecting each Registrant

There are a number of pending cases seeking damages based on allegations of federal and state common law nuisance in which we, among others, are defendants. In general, the actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance due to impacts of global warming and climate change. The plaintiffs in these actions seek recovery of damages and other relief. If these or other future actions are resolved against us, substantial modifications of our existing coal-fired power plants could be required and we might be required to limit or reduce CO_2 emissions. Such remedies could require us to purchase power from third parties to fulfill our commitments to supply power to our customers. This could have a material impact on our costs. In addition, we could be required to invest significantly in additional emission control equipment, accelerate the timing of capital expenditures, pay damages or penalties and/or halt operations. While management believes such costs should be recoverable from customers as costs of doing business in our jurisdictions where generation rates are set on a cost of service basis, without such recovery those costs could reduce our future net income and cash flows and harm our financial condition. Moreover, our results of operations and financial position could be reduced due to the timing of recovery of these investments and the expense of ongoing litigation.

We may not fully recover the costs of repairing or replacing damaged equipment in Cook Plant Unit 1 and may be required to pay additional accidental outage insurance proceeds to ratepayers. – Affecting AEP and I&M

Cook Plant Unit 1 is a 1,084 MW nuclear generating unit located in Bridgman, Michigan. In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and were within the vendor's warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Management believes that I&M should recover a significant portion of these costs through the turbine vendor's warranty, insurance and the regulatory process. I&M repaired Unit 1. It resumed operations in 2009 at slightly reduced power and a full-capacity blade was installed in 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition.

Our revenues and results of operations from selling power are subject to market risks that are beyond our control. – Affecting each Registrant

We sell power from our generation facilities into the spot market and other competitive power markets on a contractual basis. We also enter into contracts to purchase and sell electricity, natural gas, emission allowances and coal as part of our power marketing and energy trading operations. With respect to such transactions, the rate of return on our capital investments is not determined through mandated rates, and our revenues and results of operations are likely to depend, in large part, upon prevailing market prices for power in our regional markets and other competitive markets. These market prices can fluctuate substantially over relatively short periods of time. Trading margins may erode as markets mature and there may be diminished opportunities for gain should volatility decline. In addition, the FERC, which has jurisdiction over wholesale power rates, as well as RTOs that oversee some of these markets, may impose price limitations, bidding rules and other mechanisms to address some of the volatility in these markets. Power supply and other similar agreements entered into during extreme market conditions may subsequently be held to be unenforceable by a reviewing court or the FERC. Fuel and emissions prices may also be volatile, and the price we can obtain for power sales may not change at the same rate as changes in fuel and/or emissions costs. These factors could reduce our margins and therefore diminish our revenues and results of operations. Volatility in market prices for fuel and power may result from:

- Weather conditions.
- Outages of major generation or transmission facilities.
- Seasonality.
- Power usage.
- Illiquid markets.
- Transmission or transportation constraints or inefficiencies.
- Availability of competitively priced alternative energy sources.
- Demand for energy commodities.
- Natural gas, crude oil and refined products and coal production levels.
- Natural disasters, wars, embargoes and other catastrophic events.
- Federal, state and foreign energy and environmental regulation and legislation.

Our power trading (including coal, gas and emission allowances trading and power marketing) and risk management policies cannot eliminate the risk associated with these activities. – Affecting each Registrant

Our power trading (including coal, gas and emission allowances trading and power marketing) activities expose us to risks of commodity price movements. We attempt to manage our exposure by establishing and enforcing risk limits and risk management procedures. These risk limits and risk management procedures may not work as planned and cannot eliminate the risks associated with these activities. As a result, we cannot predict the impact that our energy trading and risk management decisions may have on our business, operating results or financial position.

We routinely have open trading positions in the market, within guidelines we set, resulting from the management of our trading portfolio. To the extent open trading positions exist, fluctuating commodity prices can improve or diminish our financial results and financial position.

Our power trading and risk management activities, including our power sales agreements with counterparties, rely on projections that depend heavily on judgments and assumptions by management of factors such as the future market prices and demand for power and other energy-related commodities. These factors become more difficult to predict and the calculations become less reliable the further into the future these estimates are made. Even when our policies and procedures are followed and decisions are made based on these estimates, results of operations may be diminished if the judgments and assumptions underlying those calculations prove to be inaccurate.

Parties with whom we have contracts may fail to perform their obligations, which could harm our results of operations. – Affecting each Registrant

We are exposed to the risk that counterparties that owe us money or power could breach their obligations. Should the counterparties to these arrangements fail to perform, we may be forced to enter into alternative hedging arrangements or honor underlying commitments at then-current market prices that may exceed our contractual prices, which would cause our financial results to be diminished and we might incur losses. Although our estimates take into account the expected probability of default by a counterparty, our actual exposure to a default by a counterparty may be greater than the estimates predict.

We rely on electric transmission facilities that we do not own or control. If these facilities do not provide us with adequate transmission capacity, we may not be able to deliver our wholesale electric power to the purchasers of our power. – Affecting each Registrant

We depend on transmission facilities owned and operated by other nonaffiliated power companies to deliver the power we sell at wholesale. This dependence exposes us to a variety of risks. If transmission is disrupted, or transmission capacity is inadequate, we may not be able to sell and deliver our wholesale power. If a region's power transmission infrastructure is inadequate, our recovery of wholesale costs and profits may be limited. If restrictive transmission price regulation is imposed, the transmission companies may not have sufficient incentive to invest in expansion of transmission infrastructure.

The FERC has issued electric transmission initiatives that require electric transmission services to be offered unbundled from commodity sales. Although these initiatives are designed to encourage wholesale market transactions for electricity and gas, access to transmission systems may in fact not be available if transmission capacity is insufficient because of physical constraints or because it is contractually unavailable. We also cannot predict whether transmission facilities will be expanded in specific markets to accommodate competitive access to those markets.

We do not fully hedge against price changes in commodities. – Affecting each Registrant

We routinely enter into contracts to purchase and sell electricity, natural gas, coal and emission allowances as part of our power marketing and energy and emission allowances trading operations. In connection with these trading activities, we routinely enter into financial contracts, including futures and options, over-the counter options, financially-settled swaps and other derivative contracts. These activities expose us to risks from price movements. If the values of the financial contracts change in a manner we do not anticipate, it could harm our financial position or reduce the financial contribution of our trading operations.

We manage our exposure by establishing risk limits and entering into contracts to offset some of our positions (i.e., to hedge our exposure to demand, market effects of weather and other changes in commodity prices). However, we do not always hedge the entire exposure of our operations from commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon our success in the market.

Financial derivatives reforms could increase the liquidity needs and costs of our commercial trading operations. – Affecting each Registrant

In July 2010, federal legislation was enacted to reform financial markets that significantly alter how over-the-counter (OTC) derivatives are regulated. The law increased regulatory oversight of OTC energy derivatives, including (1) requiring standardized OTC derivatives to be traded on registered exchanges regulated by the Commodity Futures Trading Commission (CFTC), (2) imposing new and potentially higher capital and margin requirements and (3) authorizing the establishment of overall volume and position limits. The law gives the CFTC authority to exempt end users of energy commodities which could reduce, but not eliminate, the applicability of these measures to us and other end users. These requirements could cause our OTC transactions to be more costly and have an adverse effect on our liquidity due to additional capital requirements. In addition, as these reforms aim to standardize OTC products it could limit the effectiveness of our hedging programs because we would have less ability to tailor OTC derivatives to match the precise risk we are seeking to manage.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

GENERATION FACILITIES

Utility Operations

At December 31, 2011, the AEP System owned (or leased where indicated) generating plants, all situated in the states in which our electric utilities serve retail customers, with net maximum power capabilities (winter rating) shown in the following tables:

AEGCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Rockport (1&2(a), 50% of each)	2	IN	Steam - Coal	1,310	1984
Lawrenceburg	6	IN	Natural Gas	1,186	2004
Total MWs				2,496	

(a) Rockport Unit 2 is leased

APCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Buck	3	VA	Hydro	9	1912
Byllesby	4	VA	Hydro	22	1912
Claytor	4	VA	Hydro	76	1939
Leesville	2	VA	Hydro	50	1964
London	3	WV	Hydro	14	1935
Marmet	3	WV	Hydro	14	1935
Niagara	2	VA	Hydro	2	1906
Reusens	5	VA	Hydro	13	1904
Winfield	3	WV	Hydro	15	1938
Smith Mountain	5	VA	Pumped Storage	586	1965
Amos (1,2 &3)	3	WV	Steam - Coal	1,600	1971
Clinch River	3	VA	Steam - Coal	705	1958
Glen Lyn	2	VA	Steam - Coal	335	1918
Kanawha River	2	WV	Steam - Coal	400	1953
Mountaineer	1	WV	Steam - Coal	1,320	1980
Sporn	2	WV	Steam - Coal	300	1950
Ceredo	6	WV	Natural Gas	516	2001
Total MWs				5,977	

I&M

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Berrien Springs	12	MI	Hydro	7	1908
Buchanan	10	MI	Hydro	4	1919
Constantine	4	MI	Hydro	1	1921
Elkhart	3	IN	Hydro	3	1913
Mottville	4	MI	Hydro	2	1923
Twin Branch	6	IN	Hydro	5	1904
Rockport (1&2 (a), 50% of each)	2	IN	Steam - Coal	1,310	1984
Tanners Creek	4	IN	Steam - Coal	995	1951
Cook	2	MI	Steam - Nuclear	2,191	1975
Total MWs				4,518	

(a) Rockport Unit 2 is leased

KPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Big Sandy	2	KY	Steam - Coal	1,078	1963

OPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Amos (3)	1	WV	Steam - Coal	1,300	1973
Beckjord (a)	1	OH	Steam - Coal	53	1969
Cardinal	1	OH	Steam - Coal	595	1967
Conesville (a)	4	OH	Steam - Coal	1,304	1957
Darby	6	OH	Natural Gas	507	2001
Gavin	2	OH	Steam - Coal	2,640	1974
Kammer	3	WV	Steam - Coal	630	1958
Mitchell	2	WV	Steam - Coal	1,560	1971
Muskingum River	5	OH	Steam - Coal	1,440	1953
Picway	1	OH	Steam - Coal	100	1926
Racine	2	OH	Hydro	48	1982
Sporn	2	WV	Steam - Coal	290	1950
Stuart (a)	4	OH	Steam - Coal	608	1971
Stuart (a)	4	OH	Oil	3	1970
Waterford	4	OH	Natural Gas	840	2003
Zimmer (a)	1	OH	Steam - Coal	330	1991
Total MWs				12,248	

(a) Jointly-owned with non-affiliated entities. Figures presented reflect only the portion owned by OPCo.

PSO

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Riverside (1&2)	2	OK	Steam - Natural Gas	909	1974
Riverside (3&4)	2	OK	Natural Gas	160	2008
Riverside	1	OK	Oil	3	1976
Northeastern (1&2)	4	OK	Steam - Natural Gas	920	1961
Northeastern	1	OK	Oil	3	1961
Southwestern (1-3)	3	OK	Steam - Natural Gas	470	1952
Southwestern (4&5)	2	OK	Natural Gas	170	2008
Southwestern	1	OK	Oil	2	1962
Comanche	3	OK	Natural Gas	260	1973
Comanche	2	OK	Oil	4	1962
Weleetka	3	OK	Natural Gas	200	1975
Weleetka	2	OK	Oil	4	1963
Northeastern (3&4)	2	OK	Steam - Coal	930	1979
Northeastern	1	OK	Oil	1	1980
Oklaunion (a)	1	TX	Steam - Coal	102	1986
Total MWs				4,138	

(a) Jointly-owned with TNC and non-affiliated entities. Figures presented reflect only the portion owned by PSO.

SWEPCo

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant or First Unit Commissioned
Arsenal Hill	1	LA	Steam - Natural Gas	110	1960
Lieberman	4	LA	Steam - Natural Gas	271	1947
Knox Lee	4	TX	Steam - Natural Gas	480	1950
Wilkes	3	TX	Steam - Natural Gas	856	1964
Lone Star	1	TX	Steam - Natural Gas	50	1954
Stall	1	LA	Natural Gas	543	2010
Mattison	4	AR	Natural Gas	312	2007
Welsh	3	TX	Steam - Coal	1,584	1977
Flint Creek	1	AR	Steam - Coal	264	1978
Pirkey	1	TX	Steam - Lignite	580	1985
Dolet Hills	1	LA	Steam - Lignite	262	1986
Total MWs				5,312	

TNC

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant Commissioned
Oklaunion (a)	1	TX	Steam - Coal	377	1986

(a) Jointly-owned with PSO and non-affiliated entities. Figures presented reflect only the portion owned by TNC.

Domestic Independent Power (Generation and Marketing Segment)

Plant Name	Units	State	Fuel Type	Net Maximum Capacity (MWs)	Year Plant Commissioned
Trent Mesa	100	TX	Wind	150	2001
Desert Sky	107	TX	Wind	161	2001
Total MWs				311	

The source of fuel in terms of total megawatts as well as a percentage of all of the generation units set forth in the tables above consists of the following:

Coal/Lignite (a)	24,302	67%
Natural Gas/Oil	8,780	24%
Nuclear	2,191	6%
Wind/Hydro/Pumped Storage	1,182	3%
Total MWs Generating Capacity	36,455	100%

(a) Does not include AEP's 43% ownership of OVEC.

Cook Nuclear Plant

The following table provides operating information relating to the Cook Plant:

	Cook Plant	
	Unit 1 (a)	**Unit 2**
Year Placed in Operation	1975	1978
Year of Expiration of NRC License	2034	2037
Nominal Net Electrical Rating in Kilowatts	1,084,000	1,107,000
Net Capacity Factors		
2011	81.3%	99.4%
2010	82.2%	80.8%
2009	2.8%	83.1%
2008	59.2%	96.6%

(a) Unit 1 Net Capacity Factor for 2008 through 2010 was impacted by a 2008 forced outage caused by a low pressure turbine blade failure event. The reduced-capacity, repaired turbine was replaced with a full-capacity, new turbine in late 2011.

New Generation

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW pulverized coal ultra-supercritical generating unit in Arkansas, which is expected to be in-service in the fourth quarter of 2012. SWEPCo owns 73% of the Turk Plant and will operate the completed facility. APCo's Dresden Plant, a new 580 MW combined-cycle natural gas generating unit in Ohio, was completed and placed in service in January 2012.

TRANSMISSION AND DISTRIBUTION FACILITIES

The following table sets forth the total overhead circuit miles of transmission and distribution lines of the AEP System and its operating companies and that portion of the total representing 765kV lines:

	Total Overhead Circuit Miles of Transmission and Distribution Lines	Circuit Miles of 765kV Lines
AEP System (a)	224,475 (b)	2,116
APCo	52,312	734
I&M	22,005	615
KGPCo	1,359	-
KPCo	11,113	258
OPCo (a)	46,413	509
PSO	21,083	-
SWEPCo	21,883	-
TCC	29,301	-
TNC	17,212	-
WPCo	1,727	-

(a) Includes 766 miles of 345,000-volt jointly owned lines.
(b) Includes 73 miles of overhead transmission lines not identified with an operating company.

TRANSMISSION OPERATIONS

The following table sets forth the total overhead circuit miles of transmission lines of ETT, OHTCo and OKTCo:

	Total Overhead Circuit Miles of Transmission Lines
ETT	445
OHTCo	31
OKTCo	36

TITLES

The AEP System's generating facilities are generally located on lands owned in fee simple. The greater portion of the transmission and distribution lines of the System has been constructed over lands of private owners pursuant to easements or along public highways and streets pursuant to appropriate statutory authority. The rights of AEP's public utility subsidiaries in the realty on which their facilities are located are considered adequate for use in the conduct of their business. Minor defects and irregularities customarily found in title to properties of like size and character may exist, but such defects and irregularities do not materially impair the use of the properties affected thereby. AEP's public utility subsidiaries generally have the right of eminent domain which permits them, if necessary, to acquire, perfect or secure titles to or easements on privately held lands used or to be used in their utility operations. Recent legislation in Ohio and Virginia has restricted the right of eminent domain previously granted for power generation purposes.

SYSTEM TRANSMISSION LINES AND FACILITY SITING

Laws in the states of Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Texas, Tennessee, Virginia and West Virginia require prior approval of sites of generating facilities and/or routes of high-voltage transmission lines. We have experienced delays and additional costs in constructing facilities as a result of proceedings conducted pursuant to such statutes, and in proceedings in which our operating companies have sought to acquire rights-of-way through condemnation. These proceedings may result in additional delays and costs in future years.

CONSTRUCTION PROGRAM

With input from its state utility commissions, the AEP System continuously assesses the adequacy of its generation, transmission, distribution and other facilities to plan and provide for the reliable supply of electric power and energy to its customers. In this assessment process, assumptions are continually being reviewed as new information becomes available, and assessments and plans are modified, as appropriate. AEP forecasts approximately $3.1 billion of construction expenditures for 2012, excluding equity AFUDC, capitalized interest and assets acquired under leases. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital.

Construction Expenditures

The following table shows construction expenditures (including environmental expenditures) during 2011, 2010 and 2009 and a current estimate of 2012 construction expenditures. Actual amounts for 2011, 2010 and 2009 and budgeted amounts for 2012 exclude equity AFUDC, capitalized interest and assets acquired under leases.

	2012 Estimate (b)	2011 Actual	2010 Actual	2009 Actual
		(in thousands)		
Total AEP System (a)	$ 3,064,700	$ 2,669,000	$ 2,345,000	$ 2,792,000
APCo	448,500	463,077	534,334	543,587
I&M	468,400	301,241	333,238	332,775
OPCo	569,400	460,125	512,637	720,300
PSO	204,100	140,326	194,896	175,122
SWEPCo (b)	475,400	551,163	420,485	596,581

(a) Includes expenditures of other subsidiaries not shown. The figure reflects construction expenditures, not equity investments in subsidiary companies.
(b) Excludes Sabine.

The System construction program is reviewed continuously and is revised from time to time in response to changes in estimates of customer demand, business and economic conditions, the cost and availability of capital, environmental requirements and other factors. Changes in construction schedules and costs, and in estimates and projections of needs for additional facilities, as well as variations from currently anticipated levels of net earnings, federal income and other taxes and other factors affecting cash requirements may increase or decrease the estimated capital requirements for the System's construction program.

POTENTIAL UNINSURED LOSSES

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including liabilities relating to damage to our generating plants and costs of replacement power. Unless allowed to be recovered through rates, future losses or liabilities which are not completely insured could have a material adverse effect on results of operations and the financial condition of AEP and other AEP System companies. For risks related to owning a nuclear generating unit, see Note 5 to the consolidated financial statements entitled Commitments, Guarantees and Contingencies under the heading Nuclear Contingencies for information with respect to nuclear incident liability insurance.

ITEM 3. LEGAL PROCEEDINGS

For a discussion of material legal proceedings, see Note 5 to the consolidated financial statements, entitled Commitments, Guarantees and Contingencies, incorporated by reference in Item 8.

ITEM 4. MINE SAFETY DISCLOSURE

The Federal Mine Safety and Health Act of 1977 (Mine Act) imposes stringent health and safety standards on various mining operations. The Mine Act and its related regulations affect numerous aspects of mining operations, including training of mine personnel, mining procedures, equipment used in mine emergency procedures, mine plans and other matters. SWEPCo, through its ownership of Dolet Hills Lignite Company (DHLC) and OPCo, through its ownership of Conesville Coal Preparation Company (CCPC) and its use of the Conner Run fly ash impoundment, are subject to the provisions of the Mine Act. OPCo is in the process of selling CCPC.

The Dodd-Frank Wall Street Reform and Consumer Protection Act and the regulations promulgated thereunder require companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. Exhibit 95 "Mine Safety Disclosure Exhibit" contains the notices of violation and proposed assessments received by DHLC, CCPC and Conner Run under the Mine Act for the year ended December 31, 2011.

PART II

ITEM 5. MARKET FOR REGISTRANTS' COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

AEP

In addition to the discussion below, the remaining information required by this item is incorporated herein by reference to the material under AEP Common Stock and Dividend Information and Note 13 to the consolidated financial statements entitled Financing Activities under the heading Dividend Restrictions in the 2011 Annual Report.

APCo, I&M, OPCo, PSO and SWEPCo

The common stock of these companies is held solely by AEP. The information regarding the amounts of cash dividends on common stock paid by these companies to AEP during 2011, 2010 and 2009 are incorporated by reference to the material under Statements of Changes in Common Shareholder's Equity and Note 13 to the consolidated financial statements entitled Financing Activities under the heading Dividend Restrictions in the 2011 Annual Reports.

During the quarter ended December 31, 2011, neither AEP (nor its publicly-traded subsidiaries) purchased equity securities that are registered by AEP (or its publicly-traded subsidiaries) pursuant to Section 12 of the Exchange Act.

ITEM 6. SELECTED FINANCIAL DATA

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Financial Discussion and Analysis in the 2011 Annual Reports.

AEP

The information required by this item is incorporated herein by reference to the material under Selected Consolidated Financial Data in the 2011 Annual Reports.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(a). Management's narrative analysis of the results of operations and other information required by Instruction I(2)(a) is incorporated herein by reference to the material under Management's Financial Discussion and Analysis in the 2011 Annual Reports.

AEP

The information required by this item is incorporated herein by reference to the material under Management's Financial Discussion and Analysis in the 2011 Annual Reports.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

AEP, APCo, I&M, OPCo, PSO and SWEPCo

The information required by this item is incorporated herein by reference to the material under Management's Financial Discussion and Analysis – Quantitative and Qualitative Disclosures about Market and Credit Risk in the 2011 Annual Reports.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

AEP, APCo, I&M, OPCo, PSO and SWEPCo

The information required by this item is incorporated herein by reference to the financial statements and financial statement schedules described under Item 15 herein.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

AEP, APCo, I&M, OPCo, PSO and SWEPCo

None.

ITEM 9A. CONTROLS AND PROCEDURES

During 2011, management, including the principal executive officer and principal financial officer of each of American Electric Power Company, Inc., Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company (each a "Registrant" and collectively the "Registrants") evaluated each respective Registrant's disclosure controls and procedures. Disclosure controls and procedures are defined as controls and other procedures of the Registrants that are designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act are recorded, processed, summarized and reported within the time periods specified in the Commission's rules and forms. Disclosure controls and procedures include, without limitation, controls and procedures designed to ensure that information required to be disclosed by the Registrants in the reports that they file or submit under the Exchange Act is accumulated and communicated to each Registrant's management, including the principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

As of December 31, 2011, these officers concluded that the disclosure controls and procedures in place are effective and provide reasonable assurance that the disclosure controls and procedures accomplished their objectives. The Registrants continually strive to improve their disclosure controls and procedures to enhance the quality of their financial reporting and to maintain dynamic systems that change as events warrant.

There have been no changes in the Registrants' internal control over financial reporting (as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Exchange Act) during the fourth quarter of 2011 that materially affected, or are reasonably likely to materially affect, the Registrants' internal control over financial reporting.

Management is required to assess and report on the effectiveness of its internal control over financial reporting as of December 31, 2011. As a result of that assessment, management determined that there were no material weaknesses as of December 31, 2011 and, therefore, concluded that each Registrant's internal control over financial reporting was effective.

Additional information required by this item of the Registrants is incorporated by reference to Management's Report on Internal Control over Financial Reporting, included in the 2011 Annual Report of each Registrant.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

AEP

Directors, Director Nomination Process and Audit Committee

Certain of the information called for in this Item 10, including the information relating to directors, is incorporated herein by reference to AEP's definitive proxy information statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2012 Annual Meeting of Shareholders including under the captions "Election of Directors," "Section 16(a) Beneficial Ownership Reporting Compliance," "AEP's Board of Directors and Committees," "Directors," "Involvement by Mr. Hoaglin in Certain Legal Proceedings" and "Shareholder Nominees for Directors."

Executive Officers

Reference also is made to the information under the caption Executive Officers of the Registrants in Part I, Item 4 of this report.

Code of Ethics

AEP's Principles of Business Conduct is the code of ethics that applies to AEP's Chief Executive Officer, Chief Financial Officer and principal accounting officer. The Principles of Business Conduct is available on AEP's website at www.aep.com. The Principles of Business Conduct will be made available, without charge, in print to any shareholder who requests such document from Investor Relations, American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215.

If any substantive amendments to the Principles of Business Conduct are made or any waivers are granted, including any implicit waiver, from a provision of the Principles of Business Conduct, to its Chief Executive Officer, Chief Financial Officer or principal accounting officer, AEP will disclose the nature of such amendment or waiver on AEP's website, www.aep.com, or in a report on Form 8-K.

Section 16(a) Beneficial Ownership Reporting Compliance

The information required by this item is incorporated herein by reference to information contained in the definitive proxy statement of AEP for the 2012 annual meeting of shareholders.

ITEM 11. EXECUTIVE COMPENSATION

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

AEP

The information called for by this Item 11 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2012 Annual Meeting including under the captions "Compensation Discussion and Analysis," "Executive Compensation" and "Director Compensation". The information set forth under the subcaption "Human Resources Committee Report" should not be deemed filed nor should it be incorporated by reference into any other filing under the Securities Act of 1933, as amended, or the Exchange Act except to the extent we specifically incorporate such report by reference therein.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

AEP

The information relating to Security Ownership of Certain Beneficial Owners is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to 2012 Annual Meeting of Shareholders under the caption "Share Ownership of Certain Beneficial Owners and Management" and "Share Ownership of Directors and Executive Officers".

EQUITY COMPENSATION PLAN INFORMATION

The following table summarizes the ability of AEP to issue common stock pursuant to equity compensation plans as of December 31, 2011:

Plan Category	(Column A) Number of Securities to be Issued upon Exercise of Outstanding Options Warrants and Rights	(Column B) Weighted Average Exercise Price of Outstanding Options, Warrants and Rights	(Column C) Number of Securities Remaining Available for Future Issuance under Equity Compensation Plans (Excluding Securities Reflected in Column A(b)
Equity Compensation Plans Approved by Security Holders (a)	320,880	$ 29.35	18,444,311
Equity Compensation Plans Not Approved by Security Holders	-	-	-
Total	320,880	$ 29.35	18,444,311

(a) Consists of shares to be issued upon exercise of outstanding options granted under the Amended and Restated American Electric Power System Long-Term Incentive Plan.

(b) AEP deducts equity compensation granted in stock units that are paid in cash, rather than AEP common shares, such as AEP's performance units and deferred stock units, from the number of shares available for future grants under the Amended and Restated American Electric Power System Long-Term Incentive Plan. The number of shares available under this plan would be 1,091,485 higher if equity compensation that is paid in cash were not deducted from this column.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS AND DIRECTOR INDEPENDENCE

APCo, I&M, OPCo, PSO and SWEPCo

Omitted pursuant to Instruction I(2)(c).

AEP

The information called for by this Item 13 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2012 Annual Meeting under the captions "Transactions with Related Persons" and "Director Independence."

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

AEP

The information called for by this Item 14 is incorporated herein by reference to AEP's definitive proxy statement (which will be filed with the SEC pursuant to Regulation 14A under the Exchange Act) relating to the 2012 Annual Meeting under the captions "Audit and Non-Audit Fees," "Audit Committee Report" and "Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor."

APCo, I&M, OPCo, PSO and SWEPCo

Each of the above is a wholly-owned subsidiary of AEP and does not have a separate audit committee. A description of the AEP Audit Committee pre-approval policies, which apply to these companies, is contained in the definitive proxy statement of AEP for the 2012 annual meeting of shareholders. The following table presents directly billed fees for professional services rendered by Deloitte & Touche LLP for the audit of these companies' annual financial statements for the years ended December 31, 2011 and 2010, and fees directly billed for other services rendered by Deloitte & Touche LLP during those periods. Deloitte & Touche LLP also provides additional professional and other services to the AEP System, the cost of which may ultimately be allocated to these companies though not billed directly to them. For a description of these fees and services, see the description of principal accounting fees and services for AEP, above.

	APCo		I&M		OPCo	
	2011	**2010**	**2011**	**2010**	**2011**	**2010**
Audit Fees	$ 2,241,610	$ 1,978,687	$ 1,610,206	$ 1,393,624	$ 2,849,269	$ 1,814,099
Audit-Related Fees	6,900	6,500	6,900	6,500	6,900	6,500
Tax Fees	9,000	9,000	12,000	12,000	18,000	9,000
Total	$ 2,257,510	$ 1,994,187	$ 1,629,106	$ 1,412,124	$ 2,874,169	$ 1,829,599

	PSO		SWEPCo	
	2011	**2010**	**2011**	**2010**
Audit Fees	$ 714,097	$ 645,180	$ 894,582	$ 975,827
Audit-Related Fees	6,900	6,500	69,750	67,500
Tax Fees	9,000	9,000	8,977	8,977
Total	$ 729,997	$ 660,680	$ 973,309	$ 1,052,304

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

The following documents are filed as a part of this report:

1. **FINANCIAL STATEMENTS:**
   The following financial statements have been incorporated herein by reference pursuant to Item 8.

   AEP and Subsidiary Companies:
   Reports of Independent Registered Public Accounting Firm; Management's Report on Internal Control over Financial Reporting; Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2011, 2010 and 2009; Consolidated Statements of Changes in Equity for the years ended December 31, 2011, 2010 and 2009; Consolidated Balance Sheets as of December 31, 2011 and 2010; Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009; Notes to Consolidated Financial Statements.

   APCo and I&M:
   Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2011, 2010 and 2009; Consolidated Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2011, 2010 and 2009; Consolidated Balance Sheets as of December 31, 2011 and 2010; Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.

   OPCo and SWEPCo:
   Consolidated Statements of Income for the years ended December 31, 2011, 2010 and 2009; Consolidated Statements of Comprehensive Income (Loss) for the years ended December 31, 2011, 2010 and 2009; Consolidated Statements of Changes in Equity for the years ended December 31, 2011, 2010 and 2009; Consolidated Balance Sheets as of December 31, 2011 and 2010; Consolidated Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.

   PSO:
   Statements of Income for the years ended December 31, 2011, 2010 and 2009; Statements of Comprehensive Income (Loss) for the years ended December 31, 2011, 2010 and 2009; Statements of Changes in Common Shareholder's Equity for the years ended December 31, 2011, 2010 and 2009; Balance Sheets as of December 31, 2011 and 2010; Statements of Cash Flows for the years ended December 31, 2011, 2010 and 2009; Notes to Financial Statements of Registrant Subsidiaries; Report of Independent Registered Public Accounting Firm.

	Page Number
2. FINANCIAL STATEMENT SCHEDULES:	
Financial Statement Schedules are listed in the Index to Financial Statement Schedules. (Certain schedules have been omitted because the required information is contained in the notes to financial statements or because such schedules are not required or are not applicable). Reports of Independent Registered Public Accounting Firm.	S-1
3. EXHIBITS:	
Exhibits for AEP, APCo, I&M, OPCo, PSO and SWEPCo are listed in the Exhibit Index beginning on page E-1 and are incorporated herein by reference.	E-1

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

American Electric Power Company, Inc.

By: /s/ Brian X. Tierney
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 28, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chief Executive Officer, President and Director	February 28, 2012
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Executive Vice President and Chief Financial Officer	February 28, 2012
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Senior Vice President, Controller and Chief Accounting Officer	February 28, 2012
(iv) A Majority of the Directors:		
*Nicholas K. Akins *David J. Anderson * James F. Cordes * Ralph D. Crosby, Jr. *Linda A. Goodspeed *Thomas E. Hoaglin *Lester A. Hudson, Jr. *Michael G. Morris *Richard C. Notebaert *Lionel L. Nowell, III *Richard L. Sandor *Sara Martinez Tucker *John F. Turner		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 28, 2012

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Appalachian Power Company
Ohio Power Company
Public Service Company of Oklahoma
Southwestern Electric Power Company

By: /s/ Brian X. Tierney
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 28, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chief Executive Officer, President and Director	February 28, 2012
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 28, 2012
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2012
(iv) A Majority of the Directors:		
*Nicholas K. Akins *Lisa M. Barton *David M. Feinberg *Mark C. McCullough *Robert P. Powers *Barbara D. Radous *Dennis E. Welch		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 28, 2012

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized. The signature of the undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

Indiana Michigan Power Company

By: /s/ Brian X. Tierney
(Brian X. Tierney, Executive Vice President and Chief Financial Officer)

Date: February 28, 2012

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated. The signature of each of the undersigned shall be deemed to relate only to matters having reference to the above-named company and any subsidiaries thereof.

Signature	Title	Date
(i) Principal Executive Officer:		
/s/ Nicholas K. Akins **(Nicholas K. Akins)**	Chief Executive Officer, President and Director	February 28, 2012
(ii) Principal Financial Officer:		
/s/ Brian X. Tierney **(Brian X. Tierney)**	Vice President, Chief Financial Officer and Director	February 28, 2012
(iii) Principal Accounting Officer:		
/s/ Joseph M. Buonaiuto **(Joseph M. Buonaiuto)**	Controller and Chief Accounting Officer	February 28, 2012
(iv) A Majority of the Directors:		
*Nicholas K. Akins *Lisa M. Barton *Sarah L. Bodner *Paul Chodak, III *J. Edward Ehler *Allen R. Glassburn *Scott M. Krawec *Daniel V. Lee *Marc E. Lewis *Mark C. McCullough *Robert P. Powers		
*By: /s/ Brian X. Tierney **(Brian X. Tierney, Attorney-in-Fact)**		February 28, 2012

INDEX OF FINANCIAL STATEMENT SCHEDULES

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the consolidated financial statements of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011, and the Company's internal control over financial reporting as of December 31, 2011, and have issued our reports thereon dated February 28, 2012 (which report on the consolidated financial statements expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of new accounting pronouncements in 2011 and 2010); such consolidated financial statements and our reports are included in the Company's 2011 Annual Report (filed as Exhibit 13 to the 2011 Annual Report on Form 10-K of American Electric Power Company, Inc.) and are incorporated herein by reference. Our audits also included the financial statement schedules of the Company listed in Item 15. These financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We have audited the financial statements of Appalachian Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Ohio Power Company Consolidated, Public Service Company of Oklahoma and Southwestern Electric Power Company Consolidated (collectively the "Companies") as of December 31, 2011 and 2010, and for each of the three years in the period ended December 31, 2011, and have issued our reports thereon dated February 28, 2012 (which reports on the financial statements of Appalachian Power Company and subsidiaries, Indiana Michigan Power Company and subsidiaries, Ohio Power Company Consolidated and Public Service Company of Oklahoma express an unqualified opinion and include an explanatory paragraph relating to the adoption of a new accounting pronouncement in 2011 and which report on the financial statements of Southwestern Electric Power Company Consolidated expresses an unqualified opinion and includes an explanatory paragraph relating to the adoption of new accounting pronouncements in 2011 and 2010); such financial statements and our reports are included in the Companies' 2011 Annual Reports (filed as Exhibit 13 to the 2011 Annual Reports on Form 10-K of Appalachian Power Company, Indiana Michigan Power Company, Ohio Power Company, Public Service Company of Oklahoma and Southwestern Electric Power Company) and are incorporated herein by reference. Our audits also included the financial statement schedules of the Companies listed in Item 15. These financial statement schedules are the responsibility of the Companies' management. Our responsibility is to express an opinion based on our audits. In our opinion, such financial statement schedules, when considered in relation to the basic financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in millions, except per-share and share amounts)

	2011	2010	2009
REVENUES			
Affiliated Revenues	$ 5	$ 4	$ 2
EXPENSES			
Other Operation	23	54	18
OPERATING LOSS	(18)	(50)	(16)
Other Income (Expense):			
Interest Income	19	22	45
Interest Expense	(42)	(52)	(84)
LOSS BEFORE INCOME TAX CREDIT AND EQUITY EARNINGS	(41)	(80)	(55)
Income Tax Credit	2	-	-
Equity Earnings of Unconsolidated Subsidiaries	1,980	1,291	1,412
NET INCOME	$ 1,941	$ 1,211	$ 1,357
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	482,169,282	479,373,306	458,677,534
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.02	$ 2.53	$ 2.96
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	482,460,328	479,601,442	458,982,292
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.02	$ 2.53	$ 2.96

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in millions)

		2011		2010
CURRENT ASSETS				
Cash and Cash Equivalents	$	127	$	231
Other Temporary Investments		2		99
Advances to Affiliates		944		556
Accounts Receivable:				
General		17		18
Affiliated Companies		43		113
Total Accounts Receivable		60		131
Prepayments and Other Current Assets		7		7
TOTAL CURRENT ASSETS		1,140		1,024
PROPERTY, PLANT AND EQUIPMENT				
General		2		2
Total Property, Plant and Equipment		2		2
Accumulated Depreciation and Amortization		2		2
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET		-		-
OTHER NONCURRENT ASSETS				
Investments in Unconsolidated Subsidiaries		15,170		14,297
Affiliated Notes Receivable		290		295
Deferred Charges and Other Noncurrent Assets		59		70
TOTAL OTHER NONCURRENT ASSETS		15,519		14,662
TOTAL ASSETS	$	16,659	$	15,686

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2011 and 2010
(dollars in millions)

	2011	2010
CURRENT LIABILITIES		
Advances from Affiliates	$ -	$ 295
Accounts Payable:		
General	1	5
Affiliated Companies	445	544
Long-term Debt Due Within One Year	1	-
Short Term Debt	967	650
Accrued Interest	2	2
Other Current Liabilities	5	2
TOTAL CURRENT LIABILITIES	1,421	1,498
NONCURRENT LIABILITIES		
Long-term Debt	554	552
Deferred Credits and Other Noncurrent Liabilities	20	14
TOTAL NONCURRENT LIABILITIES	574	566
TOTAL LIABILITIES	1,995	2,064
COMMON SHAREHOLDERS' EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2011	2010
Shares Authorized	600,000,000	600,000,000
Shares Issued	503,759,460	501,114,881

	2011	2010
(20,336,592 shares and 20,307,725 shares were held in treasury at December 31, 2011 and 2010, respectively)	3,274	3,257
Paid-in Capital	5,970	5,904
Retained Earnings	5,890	4,842
Accumulated Other Comprehensive Income (Loss)	(470)	(381)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	14,664	13,622
TOTAL LIABILITIES AND SHAREHOLDERS' EQUITY	$ 16,659	$ 15,686

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
CONDENSED FINANCIAL INFORMATION
CONDENSED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 1,941	$ 1,211	$ 1,357
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Equity Earnings of Unconsolidated Subsidiaries	(1,980)	(1,291)	(1,412)
Cash Dividends Received from Unconsolidated Subsidiaries	1,113	854	530
Change in Other Noncurrent Assets	2	-	5
Change in Other Noncurrent Liabilities	20	14	6
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	72	(93)	14
Accounts Payable	(103)	89	29
Other Current Liabilities	(3)	(12)	(3)
Net Cash Flows from Operating Activities	1,062	772	526
INVESTING ACTIVITIES			
Purchases of Investment Securities	(69)	(333)	(66)
Sales of Investment Securities	166	267	36
Change in Advances to Affiliates, Net	(388)	(299)	1,441
Capital Contributions to Unconsolidated Subsidiaries	(99)	(6)	(1,154)
Issuance of Notes Receivable to Affiliated Companies	-	(20)	(25)
Repayments of Notes Receivable from Affiliated Companies	5	300	5
Other Investing Activities	-	-	1
Net Cash Flows from (Used for) Investing Activities	(385)	(91)	238
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	92	93	1,728
Commercial Paper and Credit Facility Borrowings	429	466	-
Change in Short-term Debt, Net	769	80	119
Retirement of Long-term Debt	-	(490)	-
Change in Advances from Affiliates, Net	(295)	6	(3)
Commercial Paper and Credit Facility Repayments	(881)	(15)	(1,969)
Dividends Paid on Common Stock	(892)	(820)	(753)
Other Financing Activities	(3)	(3)	(4)
Net Cash Flows Used for Financing Activities	(781)	(683)	(882)
Net Decrease in Cash and Cash Equivalents	(104)	(2)	(118)
Cash and Cash Equivalents at Beginning of Period	231	233	351
Cash and Cash Equivalents at End of Period	$ 127	$ 231	$ 233

See Condensed Notes to Condensed Financial Information beginning on page S-7.

SCHEDULE I
AMERICAN ELECTRIC POWER COMPANY, INC. (Parent)
INDEX OF CONDENSED NOTES TO CONDENSED FINANCIAL INFORMATION

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The condensed financial information of AEP (Parent) is required as a result of the restricted net assets of consolidated subsidiaries exceeding 25% of consolidated net assets as of December 31, 2011. Parent is a public utility holding company that owns all of the outstanding common stock of its public utility subsidiaries and varying percentages of other subsidiaries, including joint ventures and equity investments. The primary source of income for Parent is equity in its subsidiaries' earnings. Its major source of cash is dividends from the subsidiaries. Parent borrows the funds for the money pool that is used by the subsidiaries for their short-term cash needs.

Income Taxes

Parent files a consolidated federal income tax return with its subsidiaries. The AEP System's current consolidated federal income tax is allocated to the AEP System companies so that their current tax expense reflects a separate return result for each company in the consolidated group. The tax benefit of Parent is allocated to its subsidiaries with taxable income.

2. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Parent and its subsidiaries are parties to environmental and other legal matters. For further discussion of commitments, guarantees and contingencies, see Note 5 in the 2011 Annual Reports.

3. FINANCING ACTIVITIES

Long-term Debt

Type of Debt and Maturity	Interest Rates at December 31, 2011	Interest Rates at December 31, 2010	Outstanding at December 31, 2011	Outstanding at December 31, 2010
			(in millions)	
Senior Unsecured Notes				
2015	5.25%	5.25%	$ 243	$ 243
Junior Subordinated Debentures				
2063	8.75%	8.75%	315	315
Fair Value of Interest Rate Hedges			7	6
Unamortized Discount, Net			(10)	(12)
Total Long-term Debt Outstanding			555	552
Long-term Debt Due Within One Year			1	-
Long-term Debt			$ 554	$ 552

Long-term debt outstanding at December 31, 2011 is payable as follows:

	2012	2013	2014	2015	2016	After 2016	Total
				(in millions)			
Principal Amount	$ 1	$ 4	$ -	$ 245	$ -	$ 315	$ 565
Unamortized Discount, Net							(10)
Total Long-term Debt Outstanding							$ 555

Short-term Debt

Parent's outstanding short-term debt was as follows:

	December 31,			
	2011		2010	
Type of Debt	Outstanding Amount	Weighted Average Interest Rate	Outstanding Amount	Weighted Average Interest Rate
	(in millions)		(in millions)	
Commercial Paper	$ 967	0.51 %	$ 650	0.52 %
Total Short-term Debt	$ 967		$ 650	

4. RELATED PARTY TRANSACTIONS

Payments on Behalf of Subsidiaries

Due to occasional time sensitivity and complexity of payments, Parent makes certain insurance, tax and benefit payments on behalf of subsidiary companies. Parent is then fully reimbursed by the subsidiary companies.

Short-term Lending to Subsidiaries

Parent uses a commercial paper program to meet the short-term borrowing needs of subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The program also allows some direct borrowers to invest excess cash with Parent.

Interest expense related to Parent's short-term borrowing is included in Interest Expense on Parent's Statements of Income. Parent incurred interest expense for amounts borrowed from subsidiaries of $199 thousand, $1 million and $3 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Interest income related to Parent's short-term lending is included in Interest Income on Parent's Statements of Income. Parent earned interest income for amounts advanced to subsidiaries of $3 million, $2 million and $11 million for the years ended December 31, 2011, 2010 and 2009, respectively.

Global Borrowing Notes

Parent issued long-term debt, portions of which were loaned to its subsidiaries. Parent pays interest on the global notes, but the subsidiaries accrue interest for their share of the global borrowing and remit the interest to Parent. Interest income related to Parent's loans to subsidiaries is included in Interest Income on Parent's statements of income. Parent earned interest income on loans to subsidiaries of $15 million, $18 million and $29 million for the years ended December 31, 2011, 2010 and 2009, respectively.

SCHEDULE II – VALUATION AND QUALIFYING ACCOUNTS AND RESERVES

AEP

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2011	$ 41,555	$ 36,457	$ 1,994	$ 47,455	$ 32,551
Year Ended December 31, 2010	37,399	36,699	(1,036)	31,507	41,555
Year Ended December 31, 2009	42,388	31,867	(2,850)	34,006	37,399

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

APCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2011	$ 6,667	$ 6,041	$ 1,535	$ 8,954	$ 5,289
Year Ended December 31, 2010	5,408	6,573	292	5,606	6,667
Year Ended December 31, 2009	6,176	4,198	(137)	4,829	5,408

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

I&M

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2011	$ 1,692	$ 151	$ -	$ 93	$ 1,750
Year Ended December 31, 2010	2,265	(139)(c)	(424)	10	1,692
Year Ended December 31, 2009	3,310	78	(783)	340	2,265

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.
(c) Recoveries on previous reserve balance.

OPCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2011	$ 3,768	$ 59	$ (10)	$ 254	$ 3,563
Year Ended December 31, 2010	6,146	59	(928)	1,509	3,768
Year Ended December 31, 2009	6,481	1,378	(1,708)	5	6,146

(a) Recoveries offset by reclasses to other liabilities.
(b) Uncollectible accounts written off.

PSO

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2011	$ 971	$ (194)(c)	$ -	$ -	$ 777
Year Ended December 31, 2010	304	709	-	42	971
Year Ended December 31, 2009	20	284	-	-	304

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.
(c) Recoveries on previous reserve balance.

SWEPCo

Description	Balance at Beginning of Period	Additions: Charged to Costs and Expenses	Additions: Charged to Other Accounts (a)	Deductions (b)	Balance at End of Period
			(in thousands)		
Deducted from Assets:					
Accumulated Provision for Uncollectible Accounts:					
Year Ended December 31, 2011	$ 588	$ 149	$ 376	$ 124	$ 989
Year Ended December 31, 2010	64	400	166	42	588
Year Ended December 31, 2009	135	-	-	71	64

(a) Recoveries on accounts previously written off.
(b) Uncollectible accounts written off.

EXHIBIT INDEX

The documents listed below are being filed or have previously been filed on behalf of the Registrants shown and are incorporated herein by reference to the documents indicated and made a part hereof. Exhibits ("Ex") not identified as previously filed are filed herewith. Exhibits designated with a dagger (†), are management contracts or compensatory plans or arrangements required to be filed as an Exhibit to this Form. Exhibits designated with an asterisk (*), are filed herewith.

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
AEP‡ File No. 1-3525		
3(a)	Composite of the Restated Certificate of Incorporation of AEP, dated April 28, 2009.	2009 Form 10-K, Ex 3(a)
*3(b)	Composite By-Laws of AEP, as amended as of May 24, 2011.	
4(a)	Indenture (for unsecured debt securities), dated as of May 1, 2001, between AEP and The Bank of New York, as Trustee.	Registration Statement No. 333-86050, Ex 4(a)(b)(c) Registration Statement No. 333-105532, Ex 4(d)(e)(f)
4(b)	Junior Subordinated Indenture dated as of March 1, 2008 between AEP and The Bank of New York as Trustee.	Registration Statement 333-156387, Ex 4(c)(d)
4(c)	Amended and Restated $1.5 Billion Credit Agreement, dated as of July 26, 2011, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and JP Morgan Chase Bank, N.A., as Administrative Agent.	Form 10-Q, Ex 4(d) July 29, 2011
4(d)	$1.75 Billion Credit Agreement, dated as of July 26, 2011, among AEP, the banks, financial institutions and other institutional lenders listed on the signature pages thereof, and Barclays Bank PLC as Administrative Agent.	Form 10-Q, Ex 4(e) July 29, 2011
10(a)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3)
10(b)	Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(b), March 31, 2006
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b) 1988 Form 10-K, Ex 10(b)(2)
10(d)	Transmission Coordination Agreement dated January 1, 1997, restated and amended, and as amended and approved by FERC in 2011 by and among, PSO, SWEPCo and AEPSC.	2009 Form 10-K, Ex 10(d)
10(e)	Amended and Restated Operating Agreement dated as of June 2, 1997, of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(e)(1)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(e)(1)	PJM West Reliability Assurance Agreement, dated as of March 14, 2001, among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(e)(2)
10(e)(2)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(e)(3)
10(f)	Lease Agreements, dated as of December 1, 1989, between AEGCo or I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32752, Ex 28(c)(1-6)(C) Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) AEGCo 1993 Form 10-K, Ex 10(c)(1-6)(B) I&M 1993 Form 10-K, Ex 10(e)(1-6)(B)
10(g)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l)
10(h)	Consent Decree with U.S. District Court dated October 9, 2007.	Form 8-K, Ex 10.1 dated October 9, 2007
†10(i)	AEP Accident Coverage Insurance Plan for Directors.	1985 Form 10-K, Ex 10(g)
†10(j)	AEP Retainer Deferral Plan for Non-Employee Directors, effective January 1, 2005, as amended February 9, 2007.	2007 Form 10-K, Ex 10(j)(i)
†10(k)	AEP Stock Unit Accumulation Plan for Non-Employee Directors, as amended.	2003 Form 10-K, Ex 10(k)(2)
†10(k)(1)(A)	First Amendment to AEP Stock Unit Accumulation Plan for Non-Employee Directors dated as of February 9, 2007.	2006 Form 10-K, Ex 10(j)(2)(A)
†10(l)	AEP System Excess Benefit Plan, Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(l)(1)(A)
†10(l)(1)	Guaranty by AEP of AEPSC Excess Benefits Plan.	1990 Form 10-K, Ex 10(h)(1)(B)
†10(l)(2)	AEP System Supplemental Retirement Savings Plan, Amended and Restated as of January 1, 2011 (Non-Qualified).	2010 Form 10-K, Ex 10(l)(2)
†10(l)(3)	AEPSC Umbrella Trust for Executives.	1993 Form 10-K, Ex 10(g)(3)
†10(l)(3)(A)	First Amendment to AEPSC Umbrella Trust for Executives.	2008 Form 10-K, Ex 10(l)(3)(A)
†10(m)	Employment Agreement dated July 29, 1998 between AEPSC and Robert P. Powers.	2002 Form 10-K, Ex 10(m)(4)
†10(m)(1)(A)	Amendment to Employment Agreement dated December 9, 2008 between AEPSC and Robert P. Powers.	2008 Form 10-K, Ex 10(m)(4)(A)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
†10(n)	AEP System Senior Officer Annual Incentive Compensation Plan, amended and restated effective December 13, 2006.	Form 8-K, Ex 10.1 dated April 25, 2007
†10(o)	AEP System Survivor Benefit Plan, effective January 27, 1998.	Form 10-Q, Ex 10, September 30, 1998
†10(o)(1)(A)	First Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 31, 2000.	2002 Form 10-K, Ex 10(o)(2)
†10(o)(2)(A)	Second Amendment to AEP System Survivor Benefit Plan, as amended and restated effective January 1, 2008.	2008 Form 10-K, Ex 10(o)(1)(B)
†10(p)	AEP System Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(p)
*†10(p)(1)(A)	First Amendment to AEP Incentive Compensation Deferral Plan Amended and Restated as of January 1, 2008.	
†10(q)	AEP System Nuclear Performance Long Term Incentive Compensation Plan dated August 1, 1998.	2002 Form 10-K, Ex 10(r)
†10(r)	Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	2008 Form 10-K, Ex 10(r)
†10(r)(1)(A)	First Amendment to Nuclear Key Contributor Retention Plan Amended and Restated as of January 1, 2008.	
†10(s)	AEP Change In Control Agreement, effective November 1, 2009.	2009 Form 10-K, Ex 10(s)
†10(t)	Amended and Restated AEP System Long-Term Incentive Plan.	Form 10-Q, Ex 10, June 30, 2010
*†10(t)(1)(A)	Performance Share Award Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	
*†10(t)(2)(A)	Restricted Stock Unit Agreement furnished to participants of the AEP System Long-Term Incentive Plan, as amended.	
†10(u)	AEP System Stock Ownership Requirement Plan Amended and Restated effective January 1, 2010.	2010 Form 10-K, Ex 10(u)
*†10(u)(1)(A)	First Amendment to AEP System Stock Ownership Requirement Plan as Amended and Restated effective January 1, 2010.	
†10(v)	Central and South West System Special Executive Retirement Plan Amended and Restated effective January 1, 2009.	2008 Form 10-K, Ex 10(v)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the AEP 2011 Annual Report (for the fiscal year ended December 31, 2011) which are incorporated by reference in this filing.	
*21	List of subsidiaries of AEP.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*95	Mine Safety Disclosure.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	
APCo‡ File No. 1-3457		
3(a)	Composite of the Restated Articles of Incorporation of APCo, amended as of March 7, 1997.	1996 Form 10-K, Ex 3(d)
3(b)	Composite By-Laws of APCo, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture (for unsecured debt securities), dated as of January 1, 1998, between APCo and The Bank of New York, As Trustee.	Registration Statement No. 333-45927, Ex 4(a)(b) Registration Statement No. 333-49071, Ex 4(b) Registration Statement No. 333-84061, Ex 4(b)(c) Registration Statement No. 333-100451, Ex 4(b)(c)(d) Registration Statement No. 333-116284, Ex 4(b)(c) Registration Statement No. 333-123348, Ex 4(b)(c) Registration Statement No. 333-136432, Ex 4(b)(c)(d) Registration Statement No. 333-161940, Ex 4(b)(c)(d)
4(b)	Company Order and Officer's Certificate to The Bank of New York Mellon Trust Company, dated May 24, 2010 establishing terms of 3.40% Senior Notes due 2015.	Form 8-K, Ex 4(a) dated May 24, 2010
4(c)	Company Order and Officer's Certificate to The Bank of New York Mellon Trust Company, N.A., dated March 25, 2011 establishing terms of 4.60% Senior Notes due 2021.	Form 8-K, Ex 4(a) dated March 25, 2011
10(a)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(D) 1989 Form 10-K, Ex 10(a)(1)(F) 1992 Form 10-K, Ex 10(a)(1)(B)
10(a)(1)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(2)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, OPCo and I&M and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b) 1988 Form 10-K, Ex 10(b)(2)
10(d)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(1)
10(d)(1)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(2)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the APCo 2011 Annual Report (for the fiscal year ended December 31, 2011) which are incorporated by reference in this filing.	
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*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
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101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

I&M‡ File No. 1-3570

3(a)	Composite of the Amended Articles of Acceptance of I&M, dated of March 7, 1997.	1996 Form 10-K, Ex 3(c)
3(b)	Composite By-Laws of I&M, amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(a)	Indenture (for unsecured debt securities), dated as of October 1, 1998, between I&M and The Bank of New York, as Trustee.	Registration Statement No. 333-88523, Ex 4(a)(b)(c) Registration Statement No. 333-58656, Ex 4(b)(c) Registration Statement No. 333-108975, Ex 4(b)(c)(d) Registration Statement No. 333-136538, Ex 4(b)(c) Registration Statement No. 333-156182, Ex 4(b)
4(b)	Company Order and Officer's Certificate to The Bank of New York, dated January 15, 2009 establishing terms of 7.00% Senior Notes, Series I due 2019.	Form 8-K, Ex 4(a) dated January 15, 2009
10(a)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No. 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(D) APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457 APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No. 1-3457
10(a)(1)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended, March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(2)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(a)(3)	Inter-Company Power Agreement, dated as of July 10, 1953, among OVEC and the Sponsoring Companies, as amended.	Registration Statement No. 2-60015, Ex 5(c) Registration Statement No. 2-67728, Ex 5(a)(3)(B) APCo 1992 Form 10-K, Ex 10(a)(2)(B), File No. 1-3457
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M, and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File No. 1-3525
10(b)(1)	Unit Power Agreement dated as of March 31, 1982 between AEGCo and I&M, as amended.	Registration Statement No. 33-32752, Ex 28(b)(1)(A)(B)
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent, as amended.	1985 Form 10-K, Ex 10(b), File No. 1-3525 1988 Form 10-K, File No. 1-3525, Ex 10(b)(2)
10(d)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(1)
10(d)(1)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(d)(2)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(3)

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(e)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(f)	Consent Decree with U.S. District Court.	Form 8-K, Ex 10.1 dated October 9, 2007
10(g)	Lease Agreements, dated as of December 1, 1989, between I&M and Wilmington Trust Company, as amended.	Registration Statement No. 33-32753, Ex 28(a)(1-6)(C) 1993 Form 10-K, Ex 10(e)(1-6)(B)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the I&M 2011 Annual Report (for the fiscal year ended December 31, 2011) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
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101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

OPCo‡ File No.1-6543

3(a)	Composite of the Amended Articles of Incorporation of OPCo, dated June 3, 2002.	Form 10-Q, Ex 3(e), June 30, 2002
3(b)	Amended Code of Regulations of OPCo.	Form 10-Q, Ex 3(b), June 30, 2008

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
3(c)	Agreement and Plan of Merger of Ohio Power Company and Columbus Southern Power Company entered into as of December 31, 2011.	Form 8-K, Ex 2.1 dated January 6, 2012
4(a)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between OPCo and Bankers Trust Company (now Deutsche Bank Trust Company Americas), as Trustee.	Registration Statement No. 333-49595, Ex 4(a)(b)(c) Registration Statement No. 333-106242, Ex 4(b)(c)(d) Registration Statement No. 333-75783, Ex 4(b)(c) Registration Statement No. 333-127913, Ex 4(b)(c) Registration Statement No. 333-139802, Ex 4(a)(b)(c) Registration Statement No. 333-139802, Ex 4(b)(c)(d)
4(b)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated April 5, 2007, establishing terms of Floating Rate Notes, Series B.	Form 8-K, Ex 4(a) dated April 5, 2007
4(c)	Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated September 24, 2009, establishing terms of 5.375% Senior Notes, Series M due 2021.	Form 8-K, Ex 4(a) dated September 24, 2009
4(d)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between OPCo and Bank One, N.A., as Trustee.	Registration Statement No. 333-127913, Ex 4(d)(e)(f)
4(e)	Indenture (for unsecured debt securities), dated as of September 1, 1997, between CSPCo (predecessor in interest to OPCo) and Bankers Trust Company, as Trustee.	Registration Statement No. 333-54025, Ex 4(a)(b)(c)(d) Registration Statement No. 333-128174, Ex 4(b)(c)(d) Registration Statement No. 333-150603. Ex 4(b)
4(f)	Indenture (for unsecured debt securities), dated as of February 1, 2003, between CSPCo (predecessor in interest to OPCo) and Bank One, N.A., as Trustee.	Registration Statement No. 333-128174, Ex 4(e)(f)(g) Registration Statement No. 333-150603 Ex 4(b)
4(g)	First Supplemental Indenture, dated as of December 31, 2011, by and between OPCo and Deutsche Bank Trust Company Americas, as trustee, supplementing the Indenture dated as of September 1, 1997 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.1 dated January 6, 2012
4(h)	Third Supplemental Indenture, dated as of December 31, 2011, by and between OPCo and The Bank of New York Mellon Trust Company, N.A., as trustee, supplementing the Indenture dated as of February 14, 2003 between CSPCo (predecessor in interest to OPCo) and the trustee.	Form 8-K, Ex 4.2 dated January 6, 2012
4(i)	CSPCo (predecessor in interest to OPCo) Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated May 16, 2008, establishing terms of 6.05% Senior Notes, Series G, due 2018.	Form 8-K, Ex 4(a), dated May 16, 2008

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
4(j)	CSPCo (predecessor in interest to OPCo) Company Order and Officer's Certificate to Deutsche Bank Trust Company Americas, dated March 16, 2010 establishing terms of floating rate notes Series A due 2012.	Form 8-K, Ex 4(a) dated March 16, 2010
10(a)	Power Agreement, dated October 15, 1952, between OVEC and United States of America, acting by and through the United States Atomic Energy Commission, and, subsequent to January 18, 1975, the Administrator of the Energy Research and Development Administration, as amended.	Registration Statement No. 2-60015, Ex 5(a) Registration Statement No. 2-63234, Ex 5(a)(1)(B) Registration Statement No. 2-66301, Ex 5(a)(1)(C) Registration Statement No. 2-67728, Ex 5(a)(1)(B) APCo 1989 Form 10-K, Ex 10(a)(1)(F), File No. 1-3457 APCo 1992 Form 10-K, Ex 10(a)(1)(B), File No.1-3457
10(a)(1)	Inter-Company Power Agreement, dated July 10, 1953, among OVEC and the Sponsoring Companies, as amended March 13, 2006.	2005 Form 10-K, Ex 10(a)(2)
10(a)(2)	Power Agreement, dated July 10, 1953, between OVEC and Indiana-Kentucky Electric Corporation, as amended.	Registration Statement No. 2-60015, Ex 5(e)
10(b)	Interconnection Agreement, dated July 6, 1951, among APCo, CSPCo, KPCo, I&M and OPCo and with AEPSC, as amended.	Registration Statement No. 2-52910, Ex 5(a) Registration Statement No. 2-61009, Ex 5(b) 1990 Form 10-K, Ex 10(a)(3), File 1-3525
10(c)	Transmission Agreement, dated April 1, 1984, among APCo, CSPCo, I&M, KPCo, OPCo and with AEPSC as agent.	1985 Form 10-K, Ex 10(b), File No. 1-3525 1988 Form 10-K, Ex 10(b)(2), File No. 1-3525
10(d)	Unit Power Agreement, dated March 15, 2007 between AEGCo and CSPCo (predecessor in interest to OPCo).	2007 Form 10-K, Ex 10(b)(2)
10(e)	Amended and Restated Operating Agreement of PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(1)
10(f)	PJM West Reliability Assurance Agreement among Load Serving Entities in the PJM West service area.	2004 Form 10-K, Ex 10(d)(2)
10(g)	Master Setoff and Netting Agreement among PJM and AEPSC on behalf of APCo, CSPCo, I&M, KPCo, OPCo, KGPCo and WPCo.	2004 Form 10-K, Ex 10(d)(3)
10(h)	Modification No. 1 to the AEP System Interim Allowance Agreement, dated July 28, 1994, among APCo, CSPCo, I&M, KPCo, OPCo and AEPSC.	1996 Form 10-K, Ex 10(l), File No. 1-3525
10(i)	Consent Decree with U.S. District Court.	Form 8-K, Item Ex 10.1 dated October 9, 2007

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(i)(1)	Amendment No. 9, dated July 1, 2003, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	Form 10-Q, Ex 10(a), September 30, 2004
10(j)	Amendment No. 1, dated October 1, 1973, to Station Agreement dated January 1, 1968, among OPCo, Buckeye and Cardinal Operating Company, and amendments thereto.	1993 Form 10-K, Ex 10(f) 2003 Form 10-K, Ex 10(e)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the OPCo 2011 Annual Report (for the fiscal year ended December 31, 2011) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*95	Mine Safety Disclosure.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
PSO‡ File No. 0-343		
3(a)	Certificate of Amendment to Restated Certificate of Incorporation of PSO.	Form 10-Q, Ex 3(a), June 30, 2008
3(b)	Composite By-Laws of PSO amended as of February 26, 2008.	2007 Form 10-K, Ex 3 (b)
4(a)	Indenture (for unsecured debt securities), dated as of November 1, 2000, between PSO and The Bank of New York, as Trustee.	Registration Statement No. 333-100623, Ex 4(a)(b) Registration Statement No. 333-114665, Ex 4(b)(c) Registration Statement No. 333-133548, Ex 4(b)(c) Registration Statement No. 333-156319, Ex 4(b)(c)
4(b)	Eighth Supplemental Indenture, dated as of November 13, 2009 between PSO and The Bank of New York Mellon, as Trustee, establishing terms of the 5.15% Senior Notes, Series H, due 2019.	Form 8-K, Ex 4(a), dated November 13, 2009
4(c)	Ninth Supplemental Indenture, dated as of January 19, 2011 between PSO and The Bank of New York Mellon Trust Company, N.A., as Trustee, establishing terms of 4.40% Senior Notes, Series I, due 2021.	Form 8-K, Ex 4(a) dated January 20, 2011
10(a)	Restated and Amended Operating Agreement, among PSO, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(a), March 31, 2006
10(b)	Transmission Coordination Agreement dated January 1, 1997, restated and amended, and as amended and approved by FERC in 2011 by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.	2009 Form 10-K Ex 10(b)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the PSO 2011 Annual Report (for the fiscal year ended December 31, 2011) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

SWEPCo‡ File No. 1-3146

3(a)	Composite of Amended Restated Certificate of Incorporation of SWEPCo.	2008 Form 10-K, Ex 3(a)
3(b)	Composite By-Laws of SWEPCo amended as of February 26, 2008.	2007 Form 10-K, Ex 3(b)
4(a)	Indenture (for unsecured debt securities), dated as of February 4, 2000, between SWEPCo and The Bank of New York, as Trustee.	Registration Statement No. 333-96213 Registration Statement No. 333-87834, Ex 4(a)(b) Registration Statement No. 333-100632, Ex 4(b) Registration Statement No. 333-108045, Ex 4(b) Registration Statement No. 333-145669, Ex 4(c)(d) Registration Statement No. 333-161539, Ex 4(b)(c)
4(b)	Eighth Supplemental Indenture dated as of March 1, 2010 between SWEPCo and The Bank of New York Mellon establishing terms of 6.20% Senior Notes, Series H, due 2040.	Form 8-K, Ex 4(a), dated March 8, 2010
4(c)	Ninth Supplemental Indenture dated as of February 1, 2012 between SWEPCo and The Bank of New York Mellon Trust Company, N.A. establishing terms of 3.55% Senior Notes, Series I, due 2022.	Form 8-K, Ex 4(a), dated February 3, 2012

Exhibit Designation	Nature of Exhibit	Previously Filed as Exhibit to:
10(a)	Restated and Amended Operating Agreement, among PSO, TCC, TNC, SWEPCo and AEPSC, Issued on February 10, 2006, Effective May 1, 2006.	Form 10-Q, Ex 10(a), March 31, 2006
10(b)	Transmission Coordination Agreement dated January 1, 1997, restated and amended, and as amended and approved by FERC in 2011 by and among, PSO, SWEPCo and AEPSC, in connection with the operation of the transmission assets of the two public utility subsidiaries.	Form 2009 10-K, Ex 10(b)
*12	Statement re: Computation of Ratios.	
*13	Copy of those portions of the SWEPCo 2011 Annual Report (for the fiscal year ended December 31, 2011) which are incorporated by reference in this filing.	
*23	Consent of Deloitte & Touche LLP.	
*24	Power of Attorney.	
*31(a)	Certification of Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*31(b)	Certification of Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.	
*32(a)	Certification of Chief Executive Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*32(b)	Certification of Chief Financial Officer Pursuant to Section 1350 of Chapter 63 of Title 18 of the United States Code.	
*95	Mine Safety Disclosure.	
101.INS	XBRL Instance Document.	
101.SCH	XBRL Taxonomy Extension Schema.	
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.	
101.DEF	XBRL Taxonomy Extension Definition Linkbase.	
101.LAB	XBRL Taxonomy Extension Label Linkbase.	
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.	

‡ Certain instruments defining the rights of holders of long-term debt of the registrants included in the financial statements of registrants filed herewith have been omitted because the total amount of securities authorized thereunder does not exceed 10% of the total assets of registrants. The registrants hereby agree to furnish a copy of any such omitted instrument to the SEC upon request.

2011 Annual Reports

American Electric Power Company, Inc. and Subsidiary Companies

Appalachian Power Company and Subsidiaries

Indiana Michigan Power Company and Subsidiaries

Ohio Power Company Consolidated

Public Service Company of Oklahoma

Southwestern Electric Power Company Consolidated

Audited Financial Statements and
Management's Financial Discussion and Analysis

AMERICAN ELECTRIC POWER

AEP: America's Energy Partner®

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF ANNUAL REPORTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc., a holding company.
AEP Consolidated	AEP and its majority owned consolidated subsidiaries and consolidated affiliates.
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, I&M, KPCo and OPCo.
AEP Foundation	AEP charitable organization created in 2005 for charitable contributions in the communities in which AEP's subsidiaries operate.
AEP Power Pool	Members are APCo, I&M, KPCo and OPCo. The AEP Power Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System or the System	American Electric Power System, an integrated electric utility system, owned and operated by AEP's electric utility subsidiaries.
AEP West companies	PSO, SWEPCo, TCC and TNC.
AEPEP	AEP Energy Partners, Inc., a subsidiary of AEP dedicated to wholesale marketing and trading, asset management and commercial and industrial sales in the deregulated Texas market.
AEPES	AEP Energy Services, Inc., a subsidiary of AEP Resources, Inc.
AEPSC	American Electric Power Service Corporation, a service subsidiary providing management and professional services to AEP and its subsidiaries.
AFUDC	Allowance for Funds Used During Construction.
AOCI	Accumulated Other Comprehensive Income.
APCo	Appalachian Power Company, an AEP electric utility subsidiary.
APSC	Arkansas Public Service Commission.
ASU	Accounting Standard Update.
BOA	Bank of America Corporation.
CAA	Clean Air Act.
CLECO	Central Louisiana Electric Company, a nonaffiliated utility company.
CO_2	Carbon Dioxide and other greenhouse gases.
Cook Plant	Donald C. Cook Nuclear Plant, a two-unit, 2,191 MW nuclear plant owned by I&M.
CSPCo	Columbus Southern Power Company, a former AEP electric utility subsidiary that was merged into OPCo effective December 31, 2011.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
CTC	Competition Transition Charge, a transition charge applied to TCC's transmission and distribution rates for stranded costs and other true-up amounts as required by the Texas Restructuring Legislation.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC and DCC Fuel IV LLC, consolidated variable interest entities formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M.
DETM	Duke Energy Trading and Marketing L.L.C., a risk management counterparty.
DHLC	Dolet Hills Lignite Company, LLC, a wholly-owned lignite mining subsidiary of SWEPCo.
E&R	Environmental compliance and transmission and distribution system reliability.
EIS	Energy Insurance Services, Inc., a nonaffiliated captive insurance company.

Term	Meaning
ENEC	Expanded Net Energy Charge.
ERCOT	Electric Reliability Council of Texas regional transmission organization.
ESP	Electric Security Plans, filed with the PUCO, pursuant to the Ohio Amendments.
ETA	Electric Transmission America, LLC an equity interest joint venture with MidAmerican Energy Holdings Company America Transco, LLC formed to own and operate electric transmission facilities in North America outside of ERCOT.
ETT	Electric Transmission Texas, LLC, an equity interest joint venture between AEP and MidAmerican Energy Holdings Company Texas Transco, LLC formed to own and operate electric transmission facilities in ERCOT.
FAC	Fuel Adjustment Clause.
FASB	Financial Accounting Standards Board.
Federal EPA	United States Environmental Protection Agency.
FERC	Federal Energy Regulatory Commission.
FGD	Flue Gas Desulfurization or Scrubbers.
FTR	Financial Transmission Right, a financial instrument that entitles the holder to receive compensation for certain congestion-related transmission charges that arise when the power grid is congested resulting in differences in locational prices.
GAAP	Accounting Principles Generally Accepted in the United States of America.
IGCC	Integrated Gasification Combined Cycle, technology that turns coal into a cleaner-burning gas.
Interconnection Agreement	An agreement by and among APCo, I&M, KPCo and OPCo, defining the sharing of costs and benefits associated with their respective generating plants.
IRS	Internal Revenue Service.
IURC	Indiana Utility Regulatory Commission.
I&M	Indiana Michigan Power Company, an AEP electric utility subsidiary.
JMG	JMG Funding LP.
KGPCo	Kingsport Power Company, an AEP electric utility subsidiary.
KPCo	Kentucky Power Company, an AEP electric utility subsidiary.
KPSC	Kentucky Public Service Commission.
kV	Kilovolt.
KWH	Kilowatthour.
LPSC	Louisiana Public Service Commission.
MISO	Midwest Independent Transmission System Operator.
MLR	Member load ratio, the method used to allocate AEP Power Pool transactions to its members.
MMBtu	Million British Thermal Units.
MPSC	Michigan Public Service Commission.
MTM	Mark-to-Market.
MW	Megawatt.
NEIL	Nuclear Electric Insurance Limited insures domestic and international nuclear utilities for the costs associated with interruptions, damages, decontaminations and related nuclear risks.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP's Nonutility Money Pool is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.

Term	Meaning
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
POLR	Provider of Last Resort revenues.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, I&M, OPCo, PSO and SWEPCo.
Risk Management Contracts	Trading and nontrading derivatives, including those derivatives designated as cash flow and fair value hedges.
Rockport Plant	A generating plant, consisting of two 1,300 MW coal-fired generating units near Rockport, Indiana, owned by AEGCo and I&M.
RTO	Regional Transmission Organization, responsible for moving electricity over large interstate areas.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.
SEET	Significantly Excessive Earnings Test.
SEC	U.S. Securities and Exchange Commission.
SIA	System Integration Agreement, effective June 15, 2000, provides contractual basis for coordinated planning, operation and maintenance of the power supply sources of the combined AEP.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool regional transmission organization.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
Texas Restructuring Legislation	Legislation enacted in 1999 to restructure the electric utility industry in Texas.
TNC	AEP Texas North Company, an AEP electric utility subsidiary.
Transition Funding	AEP Texas Central Transition Funding I LLC and AEP Texas Central Transition Funding II LLC, wholly-owned subsidiaries of TCC and consolidated variable interest entities formed for the purpose of issuing and servicing securitization bonds related to Texas restructuring law.
True-up Proceeding	A filing made under the Texas Restructuring Legislation to finalize the amount of stranded costs and other true-up items and the recovery of such amounts.
Turk Plant	John W. Turk, Jr. Plant.
Utility Money Pool	AEP System's Utility Money Pool is the centralized funding mechanism AEP uses to meet the short term cash requirements of pool participants.
VIE	Variable Interest Entity.
Virginia SCC	Virginia State Corporation Commission.
WPCo	Wheeling Power Company, an AEP electric utility subsidiary.
WVPSC	Public Service Commission of West Virginia.

FORWARD-LOOKING INFORMATION

This report made by AEP and its Registrant Subsidiaries contains forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934. Many forward-looking statements appear in "Item 7 – Management's Financial Discussion and Analysis," but there are others throughout this document which may be identified by words such as "expect," "anticipate," "intend," "plan," "believe," "will," "should," "could," "would," "project," "continue" and similar expressions, and include statements reflecting future results or guidance and statements of outlook. These matters are subject to risks and uncertainties that could cause actual results to differ materially from those projected. Forward-looking statements in this document are presented as of the date of this document. Except to the extent required by applicable law, we undertake no obligation to update or revise any forward-looking statement. Among the factors that could cause actual results to differ materially from those in the forward-looking statements are:

- The economic climate and growth in, or contraction within, our service territory and changes in market demand and demographic patterns.
- Inflationary or deflationary interest rate trends.
- Volatility in the financial markets, particularly developments affecting the availability of capital on reasonable terms and developments impairing our ability to finance new capital projects and refinance existing debt at attractive rates.
- The availability and cost of funds to finance working capital and capital needs, particularly during periods when the time lag between incurring costs and recovery is long and the costs are material.
- Electric load, customer growth and the impact of retail competition, particularly in Ohio due to the February 2012 PUCO rehearing order.
- Weather conditions, including storms, and our ability to recover significant storm restoration costs through applicable rate mechanisms.
- Available sources and costs of, and transportation for, fuels and the creditworthiness and performance of fuel suppliers and transporters.
- Availability of necessary generating capacity and the performance of our generating plants.
- Our ability to resolve I&M's Donald C. Cook Nuclear Plant Unit 1 restoration and outage-related issues through warranty, insurance and the regulatory process.
- Our ability to recover regulatory assets and stranded costs in connection with deregulation.
- Our ability to recover increases in fuel and other energy costs through regulated or competitive electric rates.
- Our ability to build or acquire generating capacity, and transmission lines and facilities (including our ability to obtain any necessary regulatory approvals and permits) when needed at acceptable prices and terms and to recover those costs (including the costs of projects that are cancelled) through applicable rate cases or competitive rates.
- New legislation, litigation and government regulation, including oversight of nuclear generation, energy commodity trading and new or heightened requirements for reduced emissions of sulfur, nitrogen, mercury, carbon, soot or particulate matter and other substances or additional regulation of fly ash and similar combustion products that could impact the continued operation and cost recovery of our plants and related assets.
- A reduction in the federal statutory tax rate.
- Timing and resolution of pending and future rate cases, negotiations and other regulatory decisions, including rate or other recovery of new investments in generation, distribution and transmission service and environmental compliance.
- Resolution of litigation.
- Our ability to constrain operation and maintenance costs.
- Our ability to develop and execute a strategy based on a view regarding prices of electricity, natural gas and other energy-related commodities.
- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading market.
- Actions of rating agencies, including changes in the ratings of our debt.
- Volatility and changes in markets for electricity, natural gas, coal, nuclear fuel and other energy-related commodities.

- Changes in utility regulation, including the implementation of ESPs and the expected legal separation and transition to market for generation in Ohio and the allocation of costs within regional transmission organizations, including PJM and SPP.
- Accounting pronouncements periodically issued by accounting standard-setting bodies.
- The impact of volatility in the capital markets on the value of the investments held by our pension, other postretirement benefit plans, captive insurance entity and nuclear decommissioning trust and the impact on future funding requirements.
- Prices and demand for power that we generate and sell at wholesale.
- Changes in technology, particularly with respect to new, developing or alternative sources of generation.
- Our ability to recover through rates or market prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.
- Our ability to successfully manage negotiations with stakeholders and obtain regulatory approval to terminate or amend the Interconnection Agreement and break up or modify the AEP Power Pool.
- Evolving public perception of the risks associated with fuels used before, during and after the generation of electricity, including nuclear fuel.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.

The forward looking statements of AEP and its registrant subsidiaries speak only as of the date of this report or as of the date they are made. AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

AEP COMMON STOCK AND DIVIDEND INFORMATION

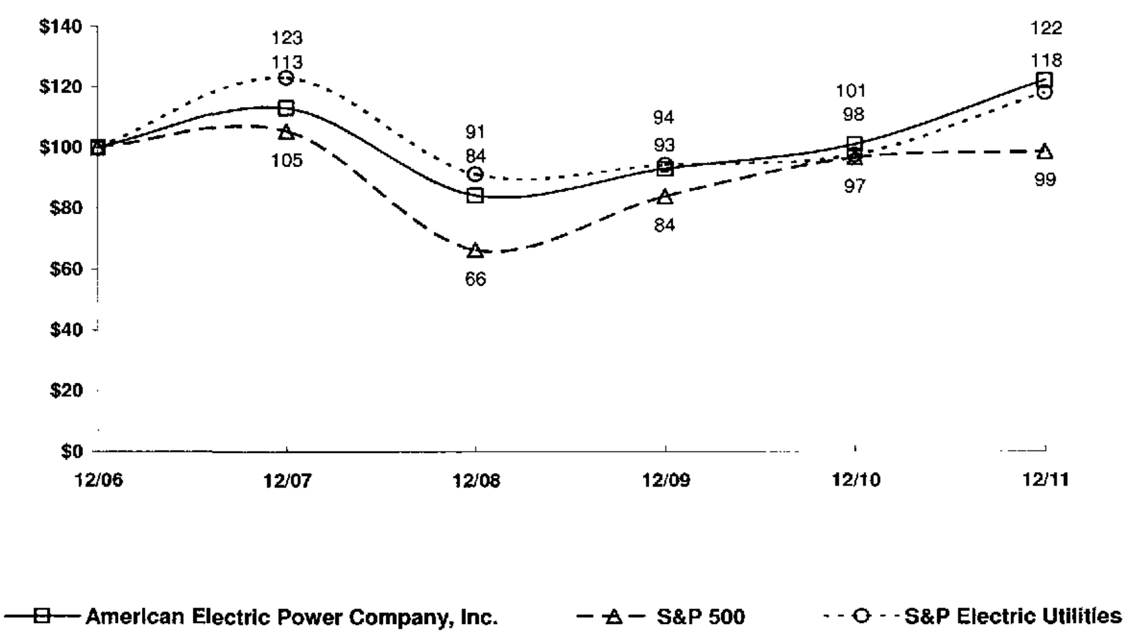
The AEP common stock quarterly high and low sales prices, quarter-end closing price and the cash dividends paid per share are shown in the following table:

Quarter Ended		High		Low		Quarter-End Closing Price		Dividend
December 31, 2011	$	41.71	$	35.85	$	41.31	$	0.47
September 30, 2011		38.98		33.09		38.02		0.46
June 30, 2011		38.99		34.37		37.68		0.46
March 31, 2011		36.92		33.47		35.14		0.46
December 31, 2010	$	37.94	$	34.92	$	35.98	$	0.46
September 30, 2010		36.93		31.87		36.23		0.42
June 30, 2010		35.00		28.17		32.30		0.42
March 31, 2010		36.86		32.68		34.18		0.41

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2011, AEP had approximately 87,000 registered shareholders.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN*

Among American Electric Power Company, Inc., the S&P 500 Index
and the S&P Electric Utilities Index



*$100 invested on 12/31/06 in stock or index, including reinvestment of dividends.
Fiscal year ending December 31.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
SELECTED CONSOLIDATED FINANCIAL DATA

	2011	2010	2009	2008	2007
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 15,116	$ 14,427	$ 13,489	$ 14,440	$ 13,380
Operating Income	$ 2,782	$ 2,663	$ 2,771	$ 2,787	$ 2,319
Income Before Discontinued Operations and Extraordinary Items	$ 1,576	$ 1,218	$ 1,370	$ 1,376	$ 1,153
Discontinued Operations, Net of Tax	-	-	-	12	24
Income Before Extraordinary Items	1,576	1,218	1,370	1,388	1,177
Extraordinary Items, Net of Tax	373	-	(5)	-	(79)
Net Income	1,949	1,218	1,365	1,388	1,098
Net Income Attributable to Noncontrolling Interests	3	4	5	5	6
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,946	1,214	1,360	1,383	1,092
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	5	3	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,941	$ 1,211	$ 1,357	$ 1,380	$ 1,089
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 55,670	$ 53,740	$ 51,684	$ 49,710	$ 46,145
Accumulated Depreciation and Amortization	18,699	18,066	17,340	16,723	16,275
Total Property, Plant and Equipment – Net	$ 36,971	$ 35,674	$ 34,344	$ 32,987	$ 29,870
Total Assets	$ 52,223	$ 50,455	$ 48,348	$ 45,155	$ 40,319
Total AEP Common Shareholders' Equity	$ 14,664	$ 13,622	$ 13,140	$ 10,693	$ 10,079
Noncontrolling Interests	$ 1	$ -	$ -	$ 17	$ 18
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ -	$ 60	$ 61	$ 61	$ 61
Long-term Debt (a)	$ 16,516	$ 16,811	$ 17,498	$ 15,983	$ 14,994
Obligations Under Capital Leases (a)	$ 458	$ 474 (b)	$ 317	$ 325	$ 371
AEP COMMON STOCK DATA					
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations and Extraordinary Items	$ 3.25	$ 2.53	$ 2.97	$ 3.40	$ 2.87
Discontinued Operations, Net of Tax	-	-	-	0.03	0.06
Income Before Extraordinary Items	3.25	2.53	2.97	3.43	2.93
Extraordinary Items, Net of Tax	0.77	-	(0.01)	-	(0.20)
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 4.02	$ 2.53	$ 2.96	$ 3.43	$ 2.73
Weighted Average Number of Basic Shares Outstanding (in millions)	482	479	459	402	399
Market Price Range:					
High	$ 41.71	$ 37.94	$ 36.51	$ 49.11	$ 51.24
Low	$ 33.09	$ 28.17	$ 24.00	$ 25.54	$ 41.67
Year-end Market Price	$ 41.31	$ 35.98	$ 34.79	$ 33.28	$ 46.56
Cash Dividends Declared per AEP Common Share	$ 1.85	$ 1.71	$ 1.64	$ 1.64	$ 1.58
Dividend Payout Ratio	46.02%	67.59%	55.41%	47.8%	57.9%
Book Value per AEP Common Share	$ 30.36	$ 28.32	$ 27.49	$ 26.35	$ 25.17

(a) Includes portion due within one year.
(b) Obligations Under Capital Leases increased primarily due to capital leases under new master lease agreements for property that was previously leased under operating leases.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
MANAGEMENT'S FINANCIAL DISCUSSION AND ANALYSIS

EXECUTIVE OVERVIEW

Company Overview

American Electric Power Company, Inc. (AEP) is one of the largest investor-owned electric public utility holding companies in the United States. Our electric utility operating companies provide generation, transmission and distribution services to more than five million retail customers in Arkansas, Indiana, Kentucky, Louisiana, Michigan, Ohio, Oklahoma, Tennessee, Texas, Virginia and West Virginia.

Our subsidiaries operate an extensive portfolio of assets including:

- Almost 36,500 megawatts of generating capacity, one of the largest complements of generation in the U.S.
- Approximately 39,000 miles of transmission lines, including 2,116 miles of 765kV lines, the backbone of the electric interconnection grid in the Eastern U.S.
- Approximately 223,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 7,600 railcars, approximately 3,300 barges, 61 towboats, 29 harbor boats and a coal handling terminal with 18 million tons of annual capacity). Our commercial barging operations annually transport approximately 44 million tons of coal and dry bulk commodities. Approximately 37% of the barging is for transportation of agricultural products, 31% for coal, 16% for steel and 16% for other commodities.

CSPCo-OPCo Merger

On December 31, 2011, CSPCo merged into OPCo with OPCo being the surviving entity. All prior disclosed amounts have been recast as if the merger occurred on the first day of the earliest reporting period. All contracts and operations of CSPCo and its subsidiary are now part of OPCo. The merger had no impact on our prior reported net income, cash flow or financial condition.

January 2012 – May 2016 Ohio ESP

In December 2011, the PUCO approved a modified stipulation for a new ESP for the period January 2012 through May 2016 that includes a standard service offer (SSO) pricing for generation. Various parties, including OPCo, filed requests for rehearing with the PUCO. In February 2012, the PUCO issued an entry on rehearing which rejected the modified stipulation and ordered a return to the 2011 ESP rates until a new rate plan is approved. Under the February 2012 rehearing order, OPCo has 30 days to notify the PUCO whether it plans to modify or withdraw its original application as filed in January 2011. Management is currently evaluating its options and the potential financial and operational impacts on OPCo. See "Ohio Electric Security Plan Filing" section of Note 3.

Ohio Customer Choice

In our Ohio service territory, various competitive retail electric service (CRES) providers are targeting retail customers by offering alternative generation service. As a result, in comparison to 2010, we lost approximately $132 million of generation and transmission related gross margin. We are recovering a portion of lost margins through collection of capacity and transmission revenues from competitive CRES providers, off-system sales and new revenues from our CRES provider. AEP Retail Energy Partners LLC, our CRES provider and member of our Generating and Marketing segment, targets retail customers in Ohio, both within and outside of our retail service territory. As a result of the February 2012 order on rehearing, OPCo is subject to significant risk of revenue loss associated with customer switching, which could materially reduce future net income and cash flows and materially impact financial condition. Currently, there are no limitations on the obligation of OPCo to provide below cost capacity rate pricing to alternative suppliers to support customers switching in Ohio. As a result of customer switching, for every 10% decline in the number of retail customers, management estimates OPCo could lose approximately $75 million of generation gross margin, net of estimated off-system sales. On February 27, 2012, OPCo filed a Motion for Relief and Request for Expedited Ruling with the PUCO related to the review of capacity charges. The filing seeks a decision within 90 days and the avoidance of an immediate change to pricing for capacity at the Reliability Pricing Model auction price, which is substantially below OPCo's cost. We are evaluating our options to challenge this capacity pricing issue.

In January 2012, we entered into an agreement to acquire BlueStar Energy Holdings, Inc. (BlueStar) and its independent retail electric supplier BlueStar Energy Solutions. BlueStar provides electric supply for retail customers in Ohio, Illinois and other deregulated electricity markets and also provides energy solutions, including demand response and energy efficiency services, nationwide. BlueStar has approximately 21,000 customer accounts. Consummation of the transaction is subject to regulatory and other approvals. The transaction is expected to close in the first quarter of 2012.

Corporate Separation

In January 2012, the PUCO approved a corporate separation plan of OPCo's generation assets to complete the transition to a fully competitive generation market by June 2015, which includes the transfer of generation assets to a nonregulated AEP subsidiary at net book value. In February 2012, as part of the PUCO's entry on rehearing which rejected the ESP modified stipulation, the PUCO revoked its approval of OPCo's corporate separation plan. Any proposed corporate separation plan will require approval by the PUCO and the FERC. Management intends to pursue Ohio corporate separation in future regulatory proceedings.

In February 2012, prior to the PUCO revoking OPCo's corporate separation plan, applications were filed with the FERC proposing to establish a new power cost sharing agreement between APCo, I&M and KPCo and transfer OPCo's generation assets to APCo, KPCo and a nonregulated AEP subsidiary. In conjunction with these filings, APCo and KPCo, which are generation capacity deficit utilities, filed an application with the FERC to acquire approximately 2,400 MWs of OPCo's 12,000 MW generation capacity at net book value. This acquisition would allow APCo and KPCo to satisfy their capacity reserve requirements in PJM and provide baseload generation to meet their customers' energy requirements. As a result of the February 2012 ESP rehearing order, we are reviewing the recoverability of all OPCo generation assets and are in the process of withdrawing the PUCO and the FERC applications. We intend to file new FERC and PUCO applications related to corporate separation. To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows. Upon receipt of all regulatory approvals, the remaining generation assets of OPCo will be owned by a nonregulated AEP subsidiary.

If we receive all regulatory approvals, our results of operations related to generation currently owned by OPCo will be determined by our ability to sell power and capacity at a profit at rates determined by the prevailing market.

Customer Demand

In comparison to 2010, cooling degree days in 2011 were up 20% in our western region and down 7% in our eastern region. While cooling degree days in our eastern region were down in comparison to 2010, they were significantly higher than normal. Our weather-normalized residential and commercial sales remained relatively flat in comparison to 2010. Industrial sales increased 4% in 2011, primarily due to a significant increase in production from Ormet, a large aluminum company, and lesser increases from other industrial customers, reflecting an increase in production by several of our metals and refinery customers. Commercial margins decreased 6% during 2011 primarily due to the loss of retail customers in Ohio. See "Ohio Customer Choice" section below.

Texas Restructuring

In July 2011, the Supreme Court of Texas overturned a 2006 PUCT order that denied recovery of capacity auction true-up amounts related to TCC securitized net recoverable stranded generation cost and remanded for reconsideration the treatment of certain tax balances under normalization rules. Based upon the Supreme Court of Texas' reversal of the PUCT's capacity auction true-up disallowance, TCC recorded $421 million of pretax income ($273 million, net of tax) in Extraordinary Items, Net of Tax on the statement of income in the third quarter of 2011.

Also in 2011, TCC recorded $271 million in pretax Carrying Costs Income on the statement of income related to the debt component of carrying costs for the period from January 2002 through December 2011. This carrying costs income represents previously unrecorded earnings associated with restructuring in Texas since 2002. The total regulatory asset related to the capacity auction true-up as of December 31, 2011 was $692 million, excluding unrecognized equity carrying costs. TCC plans to continue to recognize debt carrying costs income until securitization occurs and plans to recognize equity carrying costs income as collected from customers over the life of the securitization. Securitization is expected to be completed in March 2012.

In December 2011, the PUCT approved an unopposed stipulation allowing TCC to recover $800 million, including carrying charges, and retain contested tax balances in full satisfaction of its true-up proceeding. TCC recorded the reversal of regulatory credits of $65 million ($42 million, net of tax) and the reversal of $89 million of accumulated deferred investment tax credits ($58 million, net of tax) in Extraordinary Items, Net of Tax on the statement of income in the fourth quarter of 2011. Also, in the fourth quarter of 2011, TCC recorded $52 million in pretax Carrying Costs Income on the statement of income. See the "Texas Restructuring Appeals" and "TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes" sections of Note 3.

Regulatory Activity

The table below summarizes our significant 2011 regulatory activities:

	Requested		Approved		
Jurisdiction	**Annual Requested Base Rate Change**	**Requested Return on Common Equity**	**Annual Approved Base Rate Change**	**Approved Return on Common Equity**	**Approved Effective Date**
	(in millions)		**(in millions)**		
Indiana	$ 149	11.15%	$ (a)	(a)	(a)
Michigan	25	11.15%	15	10.2%	April 2012
Ohio	94	11.15%	- (b)	10.2%	January 2012
Virginia	126	11.65%	55	10.9%	February 2012
West Virginia	156	11.75%	51	10.0%	April 2011

(a) The Indiana base rate case is presently under review at the IURC.

(b) Although the distribution base rate did not change, approximately $47 million was being recovered through the Distribution Investment Rider (DIR). Due to the February 2012 PUCO ESP entry on rehearing, which rejected the modified stipulation for a new ESP, collection of the DIR terminated. OPCo has the right to withdraw from the stipulation in its distribution base rate case. Management is currently evaluating all of its options.

2009 – 2011 Ohio ESP

In 2011, the PUCO issued an order in the 2009 – 2011 ESP remand proceeding requiring OPCo to cease POLR billings and apply POLR collections since June 2011 first to the FAC deferral with any remaining balance to be credited to OPCo's customers in November and December 2011. As a result, in comparison to 2010, we lost approximately $71 million of pretax income related to POLR. In February 2012, the Ohio Consumers' Counsel (OCC) and the Industrial Energy Users-Ohio filed appeals with the Supreme Court of Ohio challenging various issues, including the PUCO's refusal to order retrospective relief concerning the POLR charges collected during 2009 – 2011 and various aspects of the approved environmental carrying charge, which if ordered could total up to $698 million, excluding carrying costs.

OPCo filed its 2010 Significantly Excessive Earnings Test (SEET) with the PUCO based upon the approach in the PUCO's 2009 order. Subsequent testimony and legal briefs from intervenors recommended a refund of up to $62 million of 2010 earnings, which included off-system sales in the SEET calculation. In December 2011, the PUCO staff filed testimony that recommended a $23 million refund of 2010 earnings. In the fourth quarter of 2011, OPCo provided a reserve based upon management's estimate of the probable amount for a PUCO ordered SEET refund. OPCo is required to file its 2011 SEET filing with the PUCO in 2012. Management does not currently believe that there are significantly excessive earnings in 2011. See "Ohio Electric Security Plan Filing" section of Note 3.

Virginia Rate Adjustment Clause

In January 2012, the Virginia SCC issued an order related to a generation rate adjustment clause which requested recovery of the Dresden Plant costs. The order allows APCo to recover $26 million annually, effective March 2012. See "Rate Adjustment Clauses" section of Note 3.

Turk Plant

SWEPCo is currently constructing the Turk Plant, a new base load 600 MW coal generating unit in Arkansas, which is expected to be in service in the fourth quarter of 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. SWEPCo's share of construction costs is currently estimated to be $1.3 billion, excluding AFUDC, plus an additional $122 million for transmission, excluding AFUDC. SWEPCo submitted applications with the APSC, the LPSC and the PUCT for approval to build the Turk Plant. The APSC and the LPSC approved SWEPCo's applications. However, in June 2010, the APSC issued an order which reversed and set aside the previously granted Certificate of Environmental Compatibility and Public Need (CECPN). The PUCT approved SWEPCo's application with several conditions, including a Texas jurisdictional capital costs cap. In November 2011, the Texas Court of Appeals affirmed the PUCT's order in all respects. As a result, in the fourth quarter of 2011, SWEPCo recorded a pretax write-off of $49 million in Asset Impairments and Other Related Charges on the statement of income related to the estimated excess of the Texas jurisdictional portion of the Turk Plant above the Texas jurisdictional capital costs cap. In December 2011, SWEPCo and the Texas Industrial Energy Consumers filed motions for rehearing at the Texas Court of Appeals which were denied in January 2012. SWEPCo intends to seek review of the Texas Court of Appeals decision at the Supreme Court of Texas.

Several parties, including the Hempstead County Hunting Club, the Sierra Club and the National Audubon Society had challenged the air permit, the wastewater discharge permit and the wetlands permit that were issued for the Turk Plant. In 2011, SWEPCo entered into settlement agreements with these parties which resolved all outstanding issues related to the permits and the APSC's grant of a CECPN. The parties dismissed all pending permit and CECPN challenges at the APSC, other administrative agencies and the courts. See "Turk Plant" section of Note 3.

Cook Plant

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment cost approximately $400 million. Management believes that I&M should recover a significant portion of repair and replacement costs through the turbine vendor's warranty, insurance and the regulatory process. Due to the extensive lead time required to manufacture and install new turbine rotors, I&M repaired Unit 1 and it resumed operations in December 2009. The installation of the new turbine rotors and other equipment occurred during the refueling outage of Unit 1 in the fall of 2011. If the ultimate costs of the incident are not covered by warranty, insurance or through the related regulatory process or if any future regulatory proceedings are adverse, it could have an adverse impact on net income, cash flows and financial condition. See "Cook Plant Unit 1 Fire and Shutdown" section of Note 5.

As a result of the nuclear plant situation in Japan following a March 2011 earthquake, the Nuclear Regulatory Commission (NRC) initiated a review of safety procedures and requirements for nuclear generating facilities. This review could increase procedures and testing requirements, require physical modifications to the plant and increase future operating costs at the Cook Plant. The NRC is also looking into the fuel used at eleven reactors, including the units at the Cook Plant. Their concern relates to fuel temperatures if abnormal conditions are experienced. We have been monitoring this issue and will respond to the NRC's inquiry. In addition to the review by the NRC, Congress could consider legislation tightening oversight of nuclear generating facilities. We are unable to predict the impact of potential future regulation of nuclear facilities.

LITIGATION

In the ordinary course of business, we are involved in employment, commercial, environmental and regulatory litigation. Since it is difficult to predict the outcome of these proceedings, we cannot predict the eventual resolution, timing or amount of any loss, fine or penalty. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 3 – Rate Matters and Note 5 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our net income, financial condition and cash flows.

ENVIRONMENTAL ISSUES

We are implementing a substantial capital investment program and incurring additional operational costs to comply with new environmental control requirements. We will need to make additional investments and operational changes in response to existing and anticipated requirements such as CAA requirements to reduce emissions of SO_2, NO_x, PM and hazardous air pollutants (HAPs) from fossil fuel-fired power plants, new proposals governing the beneficial use and disposal of coal combustion products and proposed clean water rules.

We are engaged in litigation about environmental issues, have been notified of potential responsibility for the clean-up of contaminated sites and incur costs for disposal of SNF and future decommissioning of our nuclear units. We are also engaged in the development of possible future requirements including the items discussed below and reductions of CO_2 emissions to address concerns about global climate change. We, along with various industry groups, affected states and other parties have challenged some of the Federal EPA requirements in court. The U.S. House of Representatives passed legislation called the Transparency in Regulatory Analysis of Impacts on the Nation (the TRAIN Act) that would delay implementation of certain Federal EPA rules and facilitate a comprehensive analysis of their impacts. The Senate is considering similar legislation. We believe that further analysis and better coordination of these environmental requirements would facilitate planning and lower overall compliance costs while achieving the same environmental goals.

We will seek recovery of expenditures for pollution control technologies and associated costs from customers through rates in regulated jurisdictions. We should be able to recover certain of these expenditures through market prices in deregulated jurisdictions. If not, the costs of environmental compliance could materially affect future net income, cash flows and possibly financial condition.

Environmental Controls Impact on the Generating Fleet

The rules and proposed environmental controls discussed in the next several sections will have a material impact on the generating units in the AEP System. We continue to evaluate the impact of these rules, project scope and technology available to achieve compliance. As of December 31, 2011, the AEP System had a total generating capacity of nearly 36,500 MWs, of which 23,900 MWs are coal-fired. We continue to refine the cost estimates of complying with these rules and other impacts of the environmental proposals on our coal-fired generating facilities. Based upon our estimates, investment to meet these proposed requirements ranges from approximately $6 billion to $7 billion between 2012 and 2020. These amounts include investments to convert 1,055 MWs of coal generation to natural gas capacity and the completion of 580 MWs of natural gas-fired generation in January 2012.

The cost estimates will change depending on the timing of implementation and whether the Federal EPA provides flexibility in the final rules. The cost estimates will also change based on: (a) the states' implementation of these regulatory programs, including the potential for state implementation plans or federal implementation plans that impose more stringent standards, (b) additional rulemaking activities in response to court decisions, (c) the actual performance of the pollution control technologies installed on our units, (d) changes in costs for new pollution controls, (e) new generating technology developments, (f) total MWs of capacity retired and replaced, including the type and amount of such replacement capacity and (g) other factors.

Subject to the factors listed above and based upon our continuing evaluation, we may retire the following plants or units of plants before or during 2015:

Company	Plant Name and Unit	Generating Capacity (in MWs)
APCo	Clinch River Plant, Unit 3	235
APCo	Glen Lyn Plant	335
APCo	Kanawha River Plant	400
APCo/OPCo	Philip Sporn Plant, Units 1-4	600
I&M	Tanners Creek Plant, Units 1-3	495
KPCo	Big Sandy Plant, Unit 1	278
OPCo	Conesville Plant, Unit 3	165
OPCo	Kammer Plant	630
OPCo	Muskingum River Plant, Units 1-4	840
OPCo	Picway Plant	100
SWEPCo	Welsh Plant, Unit 2	528
Total		4,606

Duke Energy Corporation, the operator of W. C. Beckjord Generating Station, has announced its intent to close the facility in 2015. OPCo owns 12.5% (54 MWs) of one unit at that station.

Effective December 1, 2011, we revised book depreciation rates for certain OPCo generating units consistent with shortened depreciable lives for the generating units. This change in depreciable lives is expected to result in a $54 million increase in depreciation expense in 2012. However, as a result of the January and February 2012 PUCO orders and the expected corporate separation of OPCo's generation assets and the termination of the AEP Power Pool, we are reviewing the recoverability of all OPCo generation assets.

Plans for and the timing of conversion of some of our coal units to natural gas, installing emission control equipment on other units and closure of existing units will be impacted by changes in emission requirements and demand for power. As part of environmental compliance, we are evaluating options related to maturity of the lease for Rockport Plant Unit 2 in 2022.

To the extent existing generation assets and the cost of new equipment and converted facilities are not recoverable, it could materially reduce future net income and cash flows.

Clean Air Act Requirements

The CAA establishes a comprehensive program to protect and improve the nation's air quality and control sources of air emissions. The states implement and administer many of these programs and could impose additional or more stringent requirements.

The Federal EPA issued the Clean Air Interstate Rule (CAIR) in 2005 requiring specific reductions in SO_2 and NO_x emissions from power plants. In 2008, the D.C. Circuit Court of Appeals issued a decision remanding CAIR to the Federal EPA. The Federal EPA issued the Cross-State Air Pollution Rule (CSAPR) (discussed in detail below) in August 2011 to replace CAIR. The CSAPR has been challenged in the courts, and the United States Court of Appeals for the D.C. Circuit issued an order in December 2011 staying the effective date of the rule pending judicial review. CAIR remains in effect while the litigation continues. Nearly all of the states in which our power plants are located are covered by CAIR.

The Federal EPA issued the final maximum achievable control technology (MACT) standards for coal and oil-fired power plants (discussed in detail below) in February 2012.

The Federal EPA issued a Clean Air Visibility Rule (CAVR), detailing how the CAA's requirement that certain facilities install best available retrofit technology (BART) to address regional haze in federal parks and other protected areas. BART requirements apply to facilities built between 1962 and 1977 that emit more than 250 tons per year of certain pollutants in specific industrial categories, including power plants. CAVR will be implemented through individual state implementation plans (SIPs) or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA proposed disapproval of SIPs in a few states, including Arkansas and Oklahoma. The Federal EPA finalized a FIP for Oklahoma that contains more stringent control requirements for SO_2 emissions from affected units in that state and we have challenged the FIP in the Tenth Circuit Court of Appeals. No action has been finalized in Arkansas. If the Federal EPA is upheld and similar action is taken in Arkansas, it could increase the costs of compliance, accelerate the installation of required controls and/or force the premature retirement of existing units.

In 2009, the Federal EPA issued a final mandatory reporting rule for CO_2 and other greenhouse gases covering a broad range of facilities emitting in excess of 25,000 tons of CO_2 emissions per year. The Federal EPA issued a final endangerment finding for greenhouse gas emissions from new motor vehicles in 2009. The Federal EPA determined that greenhouse gas emissions from stationary sources will be subject to regulation under the CAA beginning January 2011 and finalized its proposed scheme to streamline and phase-in regulation of stationary source CO_2 emissions through the NSR prevention of significant deterioration and Title V operating permit programs through the issuance of final federal rules, SIP calls and FIPs. The Federal EPA is reconsidering whether to include CO_2 emissions in a number of stationary source standards, including standards that apply to new and modified electric utility units and announced a settlement agreement to issue proposed new source performance standards for utility boilers.

The Federal EPA has also issued new, more stringent national ambient air quality standards (NAAQS) for SO_2, NO_x and lead, and is currently reviewing the NAAQS for ozone and PM. States are in the process of evaluating the attainment status and need for additional control measures in order to attain and maintain the new NAAQS and may develop additional requirements for our facilities as a result of those evaluations. We cannot currently predict the nature, stringency or timing of those requirements.

Notable developments in significant CAA regulatory requirements affecting our operations are discussed in the following sections.

Cross-State Air Pollution Rule (formerly the Clean Air Act Transport Rule)

In July 2010, the Federal EPA issued a proposed rule to replace CAIR that would impose new and more stringent requirements to control SO_2 and NO_x emissions from fossil fuel-fired electric generating units in 31 states and the District of Columbia.

In August 2011, the Federal EPA issued the final rule, CSAPR. The CSAPR relies on newly-created SO_2 and NO_x allowances and individual state budgets to compel further emission reductions from electric utility generating units in 28 states. Interstate trading of allowances is allowed on a restricted sub-regional basis beginning in 2012. Arkansas and Louisiana are subject only to the seasonal NO_x program in the final rule. Texas is subject to the annual programs for SO_2 and NO_x in addition to the seasonal NO_x program. The annual SO_2 allowance budgets in Indiana, Ohio and West Virginia have been reduced significantly in the final rule. A supplemental rule includes Oklahoma in the seasonal NO_x program. The supplemental rule was finalized in December 2011, with an increased NO_x emission budget for the 2012 compliance year.

In October 2011, the Federal EPA released a proposed rule revising portions of the final CSAPR. The proposed rule would correct errors in unit-specific assumptions and make available additional allowances in 10 states, including Louisiana and Texas, and provide additional allowances for the new unit set aside in Arkansas. In addition, the proposed rule would make the allowance trading assurance provisions which restrict interstate trading of allowances effective January 1, 2014 instead of January 1, 2012.

Numerous affected entities, states and other parties filed petitions to review the CSAPR in the United States Court of Appeals for the District of Columbia Circuit. Several of the petitioners filed motions to stay the implementation of the rule pending judicial review. In December 2011, the court granted the motions for stay and ordered the parties to submit schedules for expedited briefing in order to allow the case to be heard in April 2012. A final supplemental rule addressing seasonal NO_x emissions in five states was finalized in December 2011 and has been the subject of separate appeals by certain Oklahoma entities, including PSO. The Federal EPA has announced that the provisions of the supplemental rule will not be enforced while the stay of the final CSAPR remains in effect.

The time frames and stringency of the required emission reductions, coupled with the lack of robust interstate trading and the elimination of historic allowance banks, pose significant concerns for the AEP System and our electric utility customers.

Mercury and Other Hazardous Air Pollutants Regulation

In February 2012, the Federal EPA issued a rule addressing a broad range of HAPs from coal and oil-fired power plants. The rule establishes unit-specific emission rates for mercury, PM (as a surrogate for particles of nonmercury metal) and hydrogen chloride (as a surrogate for acid gases) for units burning coal on a site-wide 30-day rolling average basis. In addition, the rule proposes work practice standards, such as boiler tune-ups, for controlling emissions of organic HAPs and dioxin/furans. The effective date of the final rule is April 16, 2012 and compliance is required within three years.

The final rule contains a slightly less stringent PM limit than the original proposal and allows operators to exclude periods of startup and shutdown from the emissions averaging periods. The compliance time frame remains a serious concern. A one-year administrative extension may be available if the extension is necessary for the installation of controls or to avoid a serious reliability problem. In addition, the Federal EPA issued an enforcement policy describing the circumstances under which an administrative consent order might be issued to provide a fifth year for the installation of controls or completion of reliability upgrades. We are concerned about the availability of compliance extensions and the inability to foreclose citizen suits being filed under the CAA for failure to achieve compliance by the required deadlines.

Regional Haze

In March 2011, the Federal EPA proposed to approve in part and disapprove in part the regional haze SIP submitted by the State of Oklahoma through the Department of Environmental Quality. The Federal EPA is proposing to approve all of the NO_x control measures in the SIP and disapprove the SO_2 control measures for six electric generating units, including two units owned by PSO. The Federal EPA is proposing a FIP that would require these units to install technology capable of reducing SO_2 emissions to 0.06 pounds per million British thermal units within three years of the effective date of the FIP. PSO submitted comments on the proposed action demonstrating that the cost-effectiveness calculations performed by the Federal EPA were unsound, challenging the period for compliance with the final rule and showing that the visibility improvements secured by the proposed SIP were significant and cost-effective. The Federal EPA finalized the FIP in December 2011. PSO will appeal the FIP and pursue its claims in the Tenth Circuit Court of Appeals.

Coal Combustion Residual Rule

In June 2010, the Federal EPA published a proposed rule to regulate the disposal and beneficial re-use of coal combustion residuals, including fly ash and bottom ash generated at coal-fired electric generating units. The rule contains two alternative proposals. One proposal would impose federal hazardous waste disposal and management standards on these materials and another would allow states to retain primary authority to regulate the beneficial re-use and disposal of these materials under state solid waste management standards, including minimum federal standards for disposal and management. Both proposals would impose stringent requirements for the construction of new coal ash landfills and would require existing unlined surface impoundments to upgrade to the new standards or stop receiving coal ash and initiate closure within five years of the issuance of a final rule. In October 2011, the Federal EPA issued a notice of data availability requesting comments on a number of technical reports and other data received during the comment period for the original proposal and requesting comments on potential modeling analyses to update its risk assessment.

Currently, approximately 40% of the coal ash and other residual products from our generating facilities are re-used in the production of cement and wallboard, as structural fill or soil amendments, as abrasives or road treatment materials and for other beneficial uses. Certain of these uses would no longer be available and others are likely to significantly decline if coal ash and related materials are classified as hazardous wastes. In addition, we currently use surface impoundments and landfills to manage these materials at our generating facilities and will incur significant costs to upgrade or close and replace these existing facilities under the proposed solid waste management alternative. Regulation of these materials as hazardous wastes would significantly increase these costs. As the rule is not final, we are unable to determine a range of potential costs that are reasonably possible of occurring but expect the costs to be significant.

Clean Water Act Regulations

In April 2011, the Federal EPA issued a proposed rule setting forth standards for existing power plants that will reduce mortality of aquatic organisms pinned against a plant's cooling water intake screen (impingement) or entrained in the cooling water. Entrainment is when small fish, eggs or larvae are drawn into the cooling water system and affected by heat, chemicals or physical stress. The proposed standards affect all plants withdrawing more than two million gallons of cooling water per day and establish specific intake design and intake velocity standards meant to allow fish to avoid or escape impingement. Compliance with this standard is required within eight years of the effective date of the final rule. The proposed standard for entrainment for existing facilities requires a site-specific evaluation of the available measures for reducing entrainment. The proposed entrainment standard for new units at existing facilities requires either intake flows commensurate with closed cycle cooling or achieving entrainment reductions equivalent to 90% or greater of the reductions that could be achieved with closed cycle cooling. Plants withdrawing more than 125 million gallons of cooling water per day must submit a detailed technology study to be reviewed by the state permitting authority. We are evaluating the proposal and engaged in the collection of additional information regarding the feasibility of implementing this proposal at our facilities. We submitted comments on the proposal in July and August 2011.

Global Warming

National public policy makers and regulators in the 11 states we serve have conflicting views on global warming. We are focused on taking, in the short term, actions that we see as prudent, such as improving energy efficiency, investing in developing cost-effective and less carbon-intensive technologies and evaluating our assets across a range of plausible scenarios and outcomes. We are also active participants in a variety of public policy discussions at state and federal levels to assure that proposed new requirements are feasible and the economies of the states we serve are not placed at a competitive disadvantage.

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing CAA, permitting programs for new sources, and is expected to propose new source emissions standards for fossil fuel-fired plants in 2012.

Several states have adopted programs that directly regulate CO_2 emissions from power plants, but none of these programs are currently in effect in states where we have generating facilities. Certain of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Michigan, Ohio, Texas and Virginia). We are taking steps to comply with these requirements. In order to meet these requirements and as a key part of our corporate sustainability effort, we pledged to increase our wind power from 2007 levels. By the end of 2011, we secured, through power purchase agreements, 1,893 MW of wind and solar power.

We have taken measurable, voluntary actions to reduce and offset our CO_2 emissions. We participated in a number of voluntary programs to monitor, mitigate and reduce CO_2 emissions, but many of these programs have been discontinued due to anticipated legislative or regulatory actions. Through the end of 2010, we reduced our emissions by a cumulative 96 million metric tons from adjusted baseline levels in 1998 through 2001 under Chicago Climate Exchange (CCX) rules. Our total CO_2 emissions in 2010, as reported to CCX, were 138 million metric tons. We estimate that our 2011 emissions were approximately 139 million metric tons.

Certain groups have filed lawsuits alleging that emissions of CO_2 are a "public nuisance" and seeking injunctive relief and/or damages from small groups of coal-fired electricity generators, petroleum refiners and marketers, coal companies and others. We have been named in pending lawsuits, which we are defending. It is not possible to predict the outcome of these lawsuits or their impact on our operations or financial condition. See "Carbon Dioxide Public Nuisance Claims" and "Alaskan Villages' Claims" sections of Note 5.

Future federal and state legislation or regulations that mandate limits on the emission of CO_2 would result in significant increases in capital expenditures and operating costs, which, in turn, could lead to increased liquidity needs and higher financing costs. Excessive costs to comply with future legislation or regulations might force our utility subsidiaries to close some coal-fired facilities and could lead to possible impairment of assets. As a result, mandatory limits could have a material adverse impact on our net income, cash flows and financial condition.

Global warming creates the potential for physical and financial risk. The materiality of the risks depends on whether any physical changes occur quickly or over many decades and the extent and nature of those changes. The main physical risk from climate change that could affect AEP is changes in weather conditions. Our customers' energy needs currently vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling today represent their largest energy use. To the extent weather patterns change significantly, customers' energy use could increase or decrease depending on the duration and magnitude of any changes. Increased energy use due to weather changes could require us to invest in more generating assets, transmission and other infrastructure in the long term to serve increased load, driving the overall cost of electricity higher. Decreased energy use due to weather changes (i.e. milder winters) could affect our financial condition through lower sales and decreased revenues. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions and increased storm restoration costs. We may not recover all costs related to mitigating these physical and financial risks. Weather conditions outside of our service territory could also have an impact on our revenues, either directly through changes in the patterns of our off-system power purchases and sales or indirectly through demographic changes as people adapt to changing weather. We buy and sell electricity depending upon system needs and market opportunities. Extreme weather conditions that create high energy demand could raise electricity prices, which could increase the cost of energy we provide to our customers and could provide opportunity for increased wholesale sales and higher margins.

To the extent climate change affects a region's economic health, it could also affect our revenues. Our financial performance is tied to the health of the regional economies we serve. The price of energy, as a factor in a region's cost of living as well as an important input into the cost of goods, has an impact on the economic health of our communities. The cost of additional regulatory requirements would normally be borne by consumers through higher prices for energy and purchased goods.

For additional information on global warming, see Part I of the Annual Report under the headings entitled "Business – General – Environmental and Other Matters – Global Warming."

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is the generation, transmission and distribution of electricity. Within our Utility Operations segment, we centrally dispatch generation assets and manage our overall utility operations on an integrated basis because of the substantial impact of cost-based rates and regulatory oversight. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

While our Utility Operations segment remains our primary business segment, the advancement of an area of our business prompted us to identify a new reportable segment. Starting in the fourth quarter of 2011, we established our new Transmission Operations segment as described below:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Transmission and distribution of electricity through assets owned and operated by our ten utility operating companies.

Transmission Operations

- Development, construction and operation of transmission facilities through investments in our wholly-owned transmission subsidiaries that were established in 2009 and our transmission joint ventures. These investments have FERC-approved returns on equity.

AEP River Operations

- Commercial barging operations that transport coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers.

Generation and Marketing

- Nonregulated generation in ERCOT.
- Marketing and risk management activities primarily in ERCOT and, to a lesser extent, Ohio in PJM and MISO.

The table below presents our consolidated Income Before Extraordinary Items by segment for the years ended December 31, 2011, 2010 and 2009. We reclassified prior year amounts to conform to the current year's presentation.

	Years Ended December 31,		
	2011	2010	2009
		(in millions)	
Utility Operations	$ 1,549	$ 1,192	$ 1,325
Transmission Operations	30	9	4
AEP River Operations	45	37	47
Generation and Marketing	14	25	41
All Other (a)	(62)	(45)	(47)
Income Before Extraordinary Items	$ 1,576	$ 1,218	$ 1,370

(a) While not considered a reportable segment, All Other includes:
- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts were financial derivatives which settled and expired in the fourth quarter of 2011.
- Revenue sharing related to the Plaquemine Cogeneration Facility which ended in the fourth quarter of 2011.

AEP CONSOLIDATED

2011 Compared to 2010

Income Before Extraordinary Items in 2011 increased $358 million compared to 2010 primarily due to:

- An increase in carrying costs income due to the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable fourth quarter 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- A decrease in expenses as a result of the 2010 cost reduction initiatives.
- Successful rate proceedings in our various jurisdictions.

These increases were partially offset by:

- The loss of retail customers in Ohio to competitive retail electric service providers.
- Various Ohio adjustments in 2011, including:
  - The impairments of Sporn Unit 5 and the FGD project at Muskingum River Unit 5.
  - A net decrease due to unfavorable Ohio regulatory orders in 2011.
  - The recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund.
- The elimination of POLR charges, effective June 2011, in Ohio due to an October 2011 PUCO remand order.
- A fourth quarter 2011 write-off related to SWEPCo's Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.

Average basic shares outstanding increased to 482 million in 2011 from 479 million in 2010. Actual shares outstanding were 483 million as of December 31, 2011.

2010 Compared to 2009

Income Before Extraordinary Items in 2010 decreased $152 million compared to 2009 primarily due to charges incurred related to the 2010 cost reduction initiatives.

Average basic shares outstanding increased to 479 million in 2010 from 459 million in 2009. Actual shares outstanding were 481 million as of December 31, 2010.

Our results of operations are discussed below by operating segment.

UTILITY OPERATIONS

We believe that a discussion of the results from our Utility Operations segment on a gross margin basis is most appropriate in order to further understand the key drivers of the segment. Gross margin represents total revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances and purchased power.

	Years Ended December 31,		
	2011	2010	2009
		(in millions)	
Revenues	$ 14,200	$ 13,792	$ 12,803
Fuel and Purchased Power	5,455	4,996	4,420
Gross Margin	8,745	8,796	8,383
Other Operation and Maintenance	3,539	3,760	3,410
Asset Impairments and Other Related Charges	139	-	-
Depreciation and Amortization	1,613	1,598	1,561
Taxes Other Than Income Taxes	812	811	751
Operating Income	2,642	2,627	2,661
Interest and Investment Income	29	9	4
Carrying Costs Income	393	70	47
Allowance for Equity Funds Used During Construction	91	77	82
Interest Expense	(886)	(942)	(916)
Income Before Income Tax Expense and Equity Earnings	2,269	1,841	1,878
Equity Earnings of Unconsolidated Subsidiaries	2	2	-
Income Tax Expense	722	651	553
Income Before Extraordinary Items	$ 1,549	$ 1,192	$ 1,325

Summary of KWH Energy Sales for Utility Operations

	Years Ended December 31,		
	2011	2010	2009
		(in millions of KWHs)	
Retail:			
Residential	61,655	61,944	58,232
Commercial	50,767	50,748	49,925
Industrial	59,667	57,333	54,428
Miscellaneous	3,100	3,083	3,048
Total Retail (a)	175,189	173,108	165,633
Wholesale	40,519	32,581	29,670
Total KWHs	215,708	205,689	195,303

(a) Includes energy delivered to customers served by AEP's Texas Wires Companies.

Cooling degree days and heating degree days are metrics commonly used in the utility industry as a measure of the impact of weather on net income. In general, degree day changes in our eastern region have a larger effect on net income than changes in our western region due to the relative size of the two regions and the number of customers within each region.

Summary of Heating and Cooling Degree Days for Utility Operations

	Years Ended December 31,		
	2011	**2010**	**2009**
		(in degree days)	
Eastern Region			
Actual - Heating (a)	2,794	3,222	3,018
Normal - Heating (b)	2,980	2,983	3,040
Actual - Cooling (c)	1,215	1,307	816
Normal - Cooling (b)	1,017	1,002	1,011
Western Region			
Actual - Heating (a)	1,029	1,112	970
Normal - Heating (b)	984	980	984
Actual - Cooling (d)	3,020	2,515	2,439
Normal - Cooling (b)	2,349	2,339	2,344

(a) Eastern Region and Western Region heating degree days are calculated on a 55 degree temperature base.
(b) Normal Heating/Cooling represents the thirty-year average of degree days.
(c) Eastern Region cooling degree days are calculated on a 65 degree temperature base.
(d) Western Region cooling degree days are calculated on a 65 degree temperature base for PSO/SWEPCo and a 70 degree temperature base for TCC/TNC.

2011 Compared to 2010

Reconciliation of Year Ended December 31, 2010 to Year Ended December 31, 2011
Income from Utility Operations Before Extraordinary Items
(in millions)

Year Ended December 31, 2010	$ 1,192
Changes in Gross Margin:	
Retail Margins	(139)
Off-system Sales	44
Transmission Revenues	48
Other Revenues	(4)
Total Change in Gross Margin	(51)
Changes in Expenses and Other:	
Other Operation and Maintenance	221
Asset Impairments and Other Related Charges	(139)
Depreciation and Amortization	(15)
Taxes Other Than Income Taxes	(1)
Interest and Investment Income	20
Carrying Costs Income	323
Allowance for Equity Funds Used During Construction	14
Interest Expense	56
Total Change in Expenses and Other	479
Income Tax Expense	(71)
Year Ended December 31, 2011	$ 1,549

The major components of the decrease in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- **Retail Margins** decreased $139 million primarily due to the following:
  - A $132 million decrease attributable to Ohio customers switching to alternative competitive retail electric service (CRES) providers.
  - An $87 million decrease in weather-related usage in our eastern region primarily due to a 13% decrease in heating degree days and a 7% decrease in cooling degree days.
  - An $84 million decrease in rate related margins for APCo due to the expiration of E&R cost recovery in Virginia.
  - A $60 million decrease due to the elimination of POLR charges, effective June 2011, in Ohio as a result of the October 2011 PUCO remand order.
  - A $51 million net decrease due to unfavorable Ohio and Virginia regulatory orders.
  - A $30 million increase in other variable electric generation expenses.

  These decreases were partially offset by:
  - Successful rate proceedings in our service territories which include:
    - A $120 million rate increase for OPCo.
    - A $63 million rate increase for APCo.
    - A $30 million rate increase for SWEPCo.
    - A $27 million rate increase for KPCo.
    - A $27 million rate increase for I&M.
    - For the rate increases described above, $78 million of these increases relate to riders/trackers which have corresponding increases in other expense items below.
  - A $38 million increase in weather-related usage in our western region primarily due to a 20% increase in cooling degree days, slightly offset by a 7% decrease in heating degree days.

- A $30 million increase due to increased SWEPCo gross margin from sales to customers previously served by Valley Electric Membership Corporation (VEMCO). SWEPCo acquired VEMCO assets and began serving VEMCO customers in October 2010.
- A $14 million increase related to TCC's Transition Funding. This increase is offset by an increase in Depreciation and Amortization expenses.

- **Margins from Off-system Sales** increased $44 million primarily due to an increase in PJM capacity revenues and higher physical sales volumes, partially offset by lower trading and marketing margins.
- **Transmission Revenues** increased $48 million primarily due to net rate increases in PJM and increased transmission revenues for Ohio customers who have switched to alternative CRES providers. The increase in transmission revenues related to CRES providers partially offsets lost revenues included in Retail Margins above.

Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses decreased $221 million primarily due to the following:
  - A $280 million decrease due to expenses related to the cost reduction initiatives recorded in 2010.
  - A $54 million decrease due to the second quarter 2010 write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.
  - A $42 million decrease in administrative and general expenses primarily due to a decrease in fringe benefit expenses.
  - A $33 million decrease due to the first quarter 2011 deferral of 2010 costs related to storms and our cost reduction initiatives as allowed by the WVPSC.
  - A $27 million decrease due to the favorable fourth quarter 2011 Asset Retirement Obligation adjustment for APCo related to the early closure and previous write-off of the Mountaineer Carbon Capture and Storage Product Validation Facility.
  - An $11 million gain from the sale of land in January 2011.

  These decreases were partially offset by:
  - A $54 million increase in demand side management, energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
  - A $41 million increase due to the first quarter 2011 write-off of a portion of the West Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the WVPSC.
  - A $35 million increase related to the fourth quarter 2011 recording of an obligation to contribute to Partnership with Ohio and Ohio Growth Fund as a result of the approved December 2011 Ohio stipulation agreement.
  - A $33 million increase in storm-related expenses.
  - A $33 million increase in plant outage and other plant operating and maintenance expenses.
  - A $25 million increase due to the second quarter 2010 deferral of 2009 storm costs as allowed by the Virginia SCC.
- **Asset Impairments and Other Related Charges** in 2011 included the following:
  - A third quarter 2011 plant impairment of $48 million for Sporn Unit 5.
  - A third quarter 2011 plant impairment of $42 million for the FGD project at Muskingum River Unit 5.
  - A fourth quarter 2011 write-off of $49 million related to SWEPCo's Texas jurisdictional portion of the Turk Plant as a result of the November 2011 Texas Court of Appeals decision upholding the Texas capital cost cap.
- **Depreciation and Amortization** expenses increased $15 million primarily due to the following:
  - A $23 million increase due to the amortization of carrying costs on deferred fuel as a result of the October 2011 Ohio POLR remand order.
  - A $20 million increase in depreciation and amortization for TCC primarily due to increased amortization of TCC's Securitized Transition Assets. This increase is partially offset by an increase in revenues within Gross Margin.
  - Overall higher depreciable property balances.

These increases were partially offset by:

- A $34 million decrease in depreciation and amortization for APCo primarily due to the expiration of E&R amortization of deferred carrying costs in Virginia.

- **Interest and Investment Income** increased $20 million primarily due to interest income recorded in the third quarter of 2011 for favorable adjustments related to the 2001-2006 federal income tax audit.
- **Carrying Costs Income** increased $323 million due to the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable fourth quarter 2011 resolution of contested tax items related to the TCC stranded cost settlement.
- **Allowance for Equity Funds Used During Construction** increased $14 million primarily due to construction of the Turk and Dresden Plants and various environmental upgrades, partially offset by a decrease due to the completion of the Stall Unit in June 2010.
- **Interest Expense** decreased $56 million primarily due to lower outstanding long-term debt balances and lower long-term interest rates.
- **Income Tax Expense** increased $71 million primarily due to an increase in pretax book income, partially offset by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits and by the recording of federal and state income tax adjustments resulting from the filing of the prior year tax returns.

2010 Compared to 2009

Reconciliation of Year Ended December 31, 2009 to Year Ended December 31, 2010
Income from Utility Operations Before Discontinued Operations and Extraordinary Items
(in millions)

Year Ended December 31, 2009	$	1,325
Changes in Gross Margin:		
Retail Margins		602
Off-system Sales		53
Transmission Revenues		15
Other Revenues		(257)
Total Change in Gross Margin		413
Changes in Expenses and Other:		
Other Operation and Maintenance		(350)
Depreciation and Amortization		(37)
Taxes Other Than Income Taxes		(60)
Interest and Investment Income		5
Carrying Costs Income		23
Allowance for Equity Funds Used During Construction		(5)
Interest Expense		(26)
Equity Earnings of Unconsolidated Subsidiaries		2
Total Change in Expenses and Other		(448)
Income Tax Expense		(98)
Year Ended December 31, 2010	$	1,192

The major components of the increase in Gross Margin, defined as revenues less the related direct cost of fuel, including consumption of chemicals and emissions allowances, and purchased power were as follows:

- **Retail Margins** increased $602 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $138 million increase in the recovery of E&R costs in Virginia, costs related to the Transmission Rate Adjustment Clause in Virginia and construction financing costs in West Virginia.
    - A $49 million increase in the recovery of advanced metering costs in Texas.
    - A $43 million net rate increase for KPCo.
    - A $42 million net rate increase for SWEPCo.
    - A $39 million net rate increase for I&M.
    - A $37 million net rate increase for PSO.
    - A $14 million net rate increase in our other jurisdictions.
    - For the increases described above, $183 million of these increases relate to riders/trackers which have corresponding increases in other expense items.
  - A $229 million increase in weather-related usage primarily due to a 60% increase in cooling degree days in our eastern service territory and 7% and 15% increases in heating degree days in our eastern and western service territories, respectively.
  - A $78 million increase due to higher fuel and purchased power costs recorded in 2009 related to the Cook Plant Unit 1 (Unit 1) shutdown. This increase was offset by a corresponding decrease in Other Revenues as discussed below.

  These increases were partially offset by:
  - A $43 million decrease due to an unfavorable order related to the 2009 Significantly Excessive Earnings Test (SEET).
  - A $38 million decrease due to the termination of an I&M unit power agreement.

- **Margins from Off-system Sales** increased $53 million primarily due to increased prices and higher physical sales volumes in our eastern service territory, partially offset by lower trading and marketing margins.
- **Transmission Revenues** increased $15 million primarily due to increased revenues in the ERCOT, PJM and SPP regions.
- **Other Revenues** decreased $257 million primarily due to the Cook Plant accidental outage insurance proceeds of $185 million which ended when Unit 1 returned to service in December 2009. I&M reduced customer bills by approximately $78 million in 2009 for the cost of replacement power resulting from the Unit 1 outage. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above. Other Revenues also decreased due to lower gains on sales of emission allowances of $29 million, partially offset by sharing with customers in certain fuel clauses. This decrease in gains on sales of emission allowances was the result of lower market prices.

Total Expenses and Other and Income Tax Expense changed between years as follows:

- **Other Operation and Maintenance** expenses increased $350 million primarily due to the following:
    - A $280 million increase due to expenses related to the cost reduction initiatives in 2010.
    - A $114 million increase in demand side management, energy efficiency programs and other expenses currently recovered dollar-for-dollar in rate recovery riders/trackers within Gross Margin.
    - A $54 million increase due to the write-off of APCo's Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility as denied for recovery by the Virginia SCC.

  These increases were partially offset by:
    - An $89 million decrease in storm expenses.
- **Depreciation and Amortization** increased $37 million primarily due to new environmental improvements placed in service at APCo and OPCo and placing the Stall Unit in service at SWEPCo partially offset by lower depreciation in Arkansas and Texas as a result of SWEPCo's recent base rate orders.
- **Taxes Other Than Income Taxes** increased $60 million primarily due to the employer portion of payroll taxes incurred related to the cost reduction initiatives and higher franchise and property taxes.
- **Carrying Costs Income** increased $23 million primarily due to environmental construction in Virginia and a higher under-recovered fuel balance for OPCo.
- **Interest Expense** increased $26 million primarily due to an increase in long-term debt and a decrease in the debt component of AFUDC due to completed environmental improvements at APCo and OPCo.
- **Income Tax Expense** increased $97 million primarily due to the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D prescription drug benefits, partially offset by a decrease in pretax book income.

TRANSMISSION OPERATIONS

Wholly-owned Entities

AEP Transmission Company, LLC (AEP Transco), a subsidiary of AEP, has seven wholly-owned transmission companies. The transmission companies have been approved by the applicable commissions in Indiana, Michigan, Ohio and Oklahoma. Applications for approval of the transmission companies have been filed with the APSC, the KPSC, the LPSC, the Virginia SCC and the WVPSC and are pending approval. These seven companies consist of:

AEP East Transmission Companies

- AEP Appalachian Transmission Company, Inc. (APTCo) (covering Virginia)
- AEP Indiana Michigan Transmission Company, Inc. (IMTCo)
- AEP Kentucky Transmission Company, Inc. (KTCo)
- AEP Ohio Transmission Company, Inc. (OHTCo)
- AEP West Virginia Transmission Company, Inc. (WVTCo)

AEP West Transmission Companies

- AEP Oklahoma Transmission Company, Inc. (OKTCo)
- AEP Southwestern Transmission Company, Inc. (SWTCo) (covering Arkansas and Louisiana)

The AEP East Transmission Companies and the AEP West Transmission Companies have FERC-approved returns on common equity of 11.49% and 11.20%, respectively. AEPSC and other AEP subsidiaries provide services to the transmission companies through service agreements. Therefore, the transmission companies do not have any employees.

All of the transmission companies' capital needs are provided by Parent, AEP Transco and/or the AEP Utility Money Pool. The Utility Money Pool is used to meet the short-term borrowing needs of AEP regulated utility subsidiaries. The Utility Money Pool operates in accordance with the terms and conditions approved in regulatory orders.

Joint Venture Initiatives

We are currently participating in the following joint venture initiatives:

Project Name	Location	Projected Completion Date	Owners (Ownership %)	Total Estimated Project Costs at Completion	AEP's Investment at December 31, 2011	Approved Return on Equity
				(in thousands)		
ETT	Texas (ERCOT)	2017	MEHC Texas Transco, LLC (50%) AEP (50%)	$ 3,100,000 (a)	$ 223,527	9.96 %
PATH (b)	West Virginia	2015 (c)	FirstEnergy (50%) AEP (50%)	2,100,000 (d)	28,929	12.4 %
Prairie Wind	Kansas	2014	Westar Energy (50%) ETA (50%) (e)	225,000	1,986	12.8 %
Pioneer	Indiana	2018	Duke Energy (50%) AEP (50%)	1,000,000	-	12.54 %
RITELine IN	Indiana	2019	RTD (25%) (f) ETA (37.5%) (e) (f) AEPTHC (37.5%)	400,000	171 (g)	11.43 %
RITELine IL	Illinois	2019	Commonwealth Edison (75%) RTD (25%) (f)	1,200,000	14	11.43 %

(a) ETT's current and future estimated project cost in ERCOT over the next several years is expected to be $3.1 billion. Future projects will be evaluated on a case-by-case basis.

(b) *In September 2007, AEP Transmission Holding Company, LLC (AEPTHC) and AET PATH Company, LLC,* a subsidiary of FirstEnergy, Inc. (FirstEnergy), formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH) and its subsidiaries. The PATH subsidiaries will operate as transmission utilities owning certain electric transmission assets within PJM.

(c) PJM directed AEP and FirstEnergy to suspend current development efforts on the PATH Project, subject to those activities necessary to maintain the project in its current state, while PJM conducts more rigorous analysis of the potential need for the PATH Project as part of its continuing Regional Transmission Expansion Plan (RTEP) process. PJM's announcement specifically indicated that PJM was not directing AEP and FirstEnergy to cancel or abandon the PATH Project.

(d) PATH consists of the "West Virginia Series," which is owned equally by subsidiaries of FirstEnergy and AEP, and the "Allegheny Series" which is wholly-owned by a subsidiary of FirstEnergy. The total project is estimated to cost approximately $2.1 billion. AEP's estimated share of the project cost is approximately $700 million.

(e) ETA is a 50/50 joint venture with MidAmerican Energy Holdings Company (MEHC) America Transco, LLC and AEP. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP owns 25% of Prairie Wind Transmission, LLC (Prairie Wind) through its ownership interest in ETA.

(f) RITELine Transmission Development, LLC (RTD) is a 50/50 joint venture with Exelon Transmission Company, LLC and ETA. AEP owns 62.5% of RITELine Indiana, LLC (RITELine IN) through its ownership interest in ETA and AEPTHC. AEP owns 6.25% of RITELine Illinois, LLC (RITELine IL) through its ownership interest in ETA.

(g) RITELine IN is a consolidated variable interest entity.

For the consolidated entities within our Transmission Operations segment, we forecast approximately $350 million, excluding AFUDC, of construction expenditures for 2012. For the equity investments within our Transmission Operations segment, we forecast approximately $116 million of AEP equity contributions in 2012 to support construction expenditures and the payment of operating expenses.

2011 Compared to 2010

Income Before Extraordinary Items from our Transmission Operations segment increased from $9 million in 2010 to $30 million in 2011 primarily due to an increase in transmission investments by ETT and OHTCo.

2010 Compared to 2009

Income Before Extraordinary Items from our Transmission Operations segment increased from $4 million in 2009 to $9 million in 2010 primarily due to an increase in transmission investments by ETT.

AEP RIVER OPERATIONS

2011 Compared to 2010

Income Before Extraordinary Items from our AEP River Operations segment increased from $37 million in 2010 to $45 million in 2011 primarily due to increased coal exports, increased barge fleet size and the cost reduction initiatives in 2010, partially offset by higher fuel, maintenance and flood-related expenses.

2010 Compared to 2009

Income Before Extraordinary Items from our AEP River Operations segment decreased from $47 million in 2009 to $37 million in 2010 primarily due to expenses related to cost reduction initiatives, increased interest expense on new equipment financing, a property casualty loss in 2010 and a gain on the sale of two older towboats in 2009.

GENERATION AND MARKETING

2011 Compared to 2010

Income Before Extraordinary Items from our Generation and Marketing segment decreased from $25 million in 2010 to $14 million in 2011 primarily due to lower gross margins at the Oklaunion Plant.

2010 Compared to 2009

Income Before Extraordinary Items from our Generation and Marketing segment decreased from $41 million in 2009 to $25 million in 2010 primarily due to reduced inception gains from ERCOT marketing activities, reduced plant performance due to lower power prices in ERCOT, partially offset by positive hedging activities on our generation assets and increased income from our wind farm operations.

ALL OTHER

2011 Compared to 2010

Income Before Extraordinary Items from All Other decreased from a loss of $45 million in 2010 to a loss of $62 million in 2011 primarily due to a loss incurred in 2011 related to the settlement of litigation with BOA and Enron and a gain on the sale of our remaining shares of Intercontinental Exchange, Inc. (ICE) in 2010 partially offset by a contribution to AEP's charitable foundation in 2010.

2010 Compared to 2009

Income Before Extraordinary Items from All Other increased from a loss of $47 million in 2009 to a loss of $45 million in 2010 primarily due to a gain on the sale of our remaining shares of ICE in 2010 and a decrease in various parent related expenses partially offset by a 2010 contribution to AEP's charitable foundation and losses on the sales of assets.

AEP SYSTEM INCOME TAXES

2011 Compared to 2010

Income Tax Expense increased $175 million primarily due to an increase in pretax book income and the unrealized capital loss valuation allowance related to a deferred tax asset associated with the settlement of litigation with BOA and Enron, offset in part by the 2010 tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits and by the recording of federal and state income tax adjustments resulting from the filing of prior year tax returns.

2010 Compared to 2009

Income Tax Expense increased $68 million primarily due to the regulatory accounting treatment of state income taxes, other book/tax differences which are accounted for on a flow-through basis and the tax treatment associated with the future reimbursement of Medicare Part D retiree prescription drug benefits, offset in part by a decrease in pretax book income.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31,			
	2011		2010	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 16,516	50.3 %	$ 16,811	52.8 %
Short-term Debt	1,650	5.0	1,346	4.2
Total Debt	18,166	55.3	18,157	57.0
Preferred Stock of Subsidiaries	-	-	60	0.2
AEP Common Equity	14,664	44.7	13,622	42.8
Noncontrolling Interests	1	-	-	-
Total Debt and Equity Capitalization	$ 32,831	100.0 %	$ 31,839	100.0 %

Our ratio of debt-to-total capital decreased from 57% in 2010 to 55.3% in 2011 primarily due to an increase in common equity. This increase in common equity is primarily the result of the third quarter 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts that were originally written off in 2005 and a related favorable fourth quarter 2011 resolution of contested tax items related to the TCC stranded cost settlement.

Liquidity

Liquidity, or access to cash, is an important factor in determining our financial stability. We believe we have adequate liquidity under our existing credit facilities. At December 31, 2011, we had $3.25 billion in aggregate credit facility commitments to support our operations. Additional liquidity is available from cash from operations and a sale of receivables agreement. We are committed to maintaining adequate liquidity. We generally use short-term borrowings to fund working capital needs, property acquisitions and construction until long-term funding is arranged. Sources of long-term funding include issuance of long-term debt, sale-leaseback or leasing agreements or common stock.

Credit Facilities

We manage our liquidity by maintaining adequate external financing commitments. At December 31, 2011, our available liquidity was approximately $2.4 billion as illustrated in the table below:

	Amount (in millions)	Maturity
Commercial Paper Backup:		
Revolving Credit Facility	$ 1,500	June 2015
Revolving Credit Facility	1,750	July 2016
Total	3,250	
Cash and Cash Equivalents	221	
Total Liquidity Sources	3,471	
Less: AEP Commercial Paper Outstanding	967	
Letters of Credit Issued	134	
Net Available Liquidity	$ 2,370	

We have credit facilities totaling $3.25 billion to support our commercial paper program. The credit facilities allow us to issue letters of credit in an amount up to $1.35 billion. In July 2011, we replaced the $1.5 billion facility due in 2012 with a new $1.75 billion facility maturing in July 2016 and extended the $1.5 billion facility due in 2013 to expire in June 2015.

In March 2011, we terminated a $478 million credit facility, used for letters of credit to support variable rate debt. In March 2011, we also issued bilateral letters of credit to support the remarketing of $357 million of variable rate debt and reacquired $115 million which a trustee holds on our behalf.

We use our commercial paper program to meet the short-term borrowing needs of the subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. The maximum amount of commercial paper outstanding during 2011 was $1.2 billion. The weighted-average interest rate for our commercial paper during 2011 was 0.4%.

Financing Plan

In March 2012, TCC plans to issue $800 million of securitization bonds as approved by the PUCT for recovery of capacity auction true-up amounts over 13 years. We are also evaluating potential securitization of certain deferred regulatory assets in Ohio and West Virginia. Recent legislation in Ohio allows the securitization of deferred FAC costs and certain other regulatory assets. Legislation has been introduced in West Virginia to allow the WVPSC to consider securitization of deferred ENEC costs.

At December 31, 2011, we have $1.4 billion of long-term debt due within one year which includes $572 million of Pollution Control Bonds with mandatory tender dates and credit support for variable interest rates that requires the debt be classified as current. Also included in our long-term debt due within one year is $273 million of securitization bonds and DCC Fuel notes payable which will be repaid. We plan to refinance a portion of our maturities. Proceeds from new issuances and the TCC securitization may limit the amount of the remaining long-term debt due within one year that needs to be refinanced.

Securitized Accounts Receivables

In 2011, we renewed our receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables with an increase to $800 million for the months of July, August and September to accommodate seasonal demand. A commitment of $375 million with the seasonal increase to $425 million expires in June 2012 and the remaining commitment of $375 million expires in June 2014. We intend to extend or replace the agreement expiring in June 2012 on or before its maturity.

Debt Covenants and Borrowing Limitations

Our revolving credit agreements contain certain covenants and require us to maintain our percentage of debt to total capitalization at a level that does not exceed 67.5%. The method for calculating outstanding debt and capitalization is contractually defined in our revolving credit agreements. Debt as defined in the revolving credit agreements excludes junior subordinated debentures, securitization bonds and debt of AEP Credit. At December 31, 2011, this contractually-defined percentage was 51.1%. Nonperformance under these covenants could result in an event of default under these credit agreements. At December 31, 2011, we complied with all of the covenants contained in these credit agreements. In addition, the acceleration of our payment obligations, or the obligations of certain of our major subsidiaries, prior to maturity under any other agreement or instrument relating to debt outstanding in excess of $50 million, would cause an event of default under these credit agreements and in a majority of our non-exchange traded commodity contracts which would permit the lenders and counterparties to declare the outstanding amounts payable. However, a default under our non-exchange traded commodity contracts does not cause an event of default under our revolving credit agreements.

The revolving credit facilities do not permit the lenders to refuse a draw on any facility if a material adverse change occurs.

Utility Money Pool borrowings and external borrowings may not exceed amounts authorized by regulatory orders. At December 31, 2011, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.47 per share in January 2012. Future dividends may vary depending upon our profit levels, operating cash flow levels and capital requirements, as well as financial and other business conditions existing at the time. Our income derives from our common stock equity in the earnings of our utility subsidiaries. Various financing arrangements and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends.

We have the option to defer interest payments on the AEP Junior Subordinated Debentures for one or more periods of up to 10 consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, repurchase or acquire, our common stock.

We do not believe restrictions related to our various financing arrangements and regulatory requirements will have any significant impact on Parent's ability to access cash to meet the payment of dividends on its common stock.

Credit Ratings

We do not have any credit arrangements that would require material changes in payment schedules or terminations as a result of a credit downgrade, but our access to the commercial paper market may depend on our credit ratings. In addition, downgrades in our credit ratings by one of the rating agencies could increase our borrowing costs. Counterparty concerns about the credit quality of AEP or its utility subsidiaries could subject us to additional collateral demands under adequate assurance clauses under our derivative and non-derivative energy contracts.

CASH FLOW

Managing our cash flows is a major factor in maintaining our liquidity strength.

	Years Ended December 31, 2011	2010	2009
		(in millions)	
Cash and Cash Equivalents at Beginning of Period	$ 294	$ 490	$ 411
Net Cash Flows from Operating Activities	3,788	2,662	2,475
Net Cash Flows Used for Investing Activities	(2,890)	(2,523)	(2,916)
Net Cash Flows from (Used for) Financing Activities	(971)	(335)	520
Net Increase (Decrease) in Cash and Cash Equivalents	(73)	(196)	79
Cash and Cash Equivalents at End of Period	$ 221	$ 294	$ 490

Cash from operations and short-term borrowings provides working capital and allows us to meet other short-term cash needs.

Operating Activities

	Years Ended December 31, 2011	2010	2009
		(in millions)	
Net Income	$ 1,949	$ 1,218	$ 1,365
Depreciation and Amortization	1,655	1,641	1,597
Other	184	(197)	(487)
Net Cash Flows from Operating Activities	$ 3,788	$ 2,662	$ 2,475

Net Cash Flows from Operating Activities were $3.8 billion in 2011 consisting primarily of Net Income of $1.9 billion and $1.7 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Following a Supreme Court of Texas reversal of the PUCT's capacity auction true-up disallowance and the PUCT's approval of a stipulation agreement, we recorded Extraordinary Items, Net of Tax of $373 million for the 2011 recognition of a regulatory asset related to TCC capacity auction true-up amounts and the reversal of tax related regulatory credits. We also recorded $393 million in Carrying Costs Income primarily related to the Texas restructuring appeals. A significant change in other items includes the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to bonus depreciation provisions in the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Jobs Creation Act, the settlement with BOA and Enron and an increase in tax versus book temporary differences from operations. In February 2011, we paid $425 million to BOA of which $211 million was used to settle litigation with BOA and Enron. The remaining $214 million was used to acquire cushion gas as discussed in Investing Activities below. During 2011, we also contributed $450 million to our qualified pension trust.

Net Cash Flows from Operating Activities were $2.7 billion in 2010 consisting primarily of Net Income of $1.2 billion and $1.6 billion of noncash Depreciation and Amortization. Other changes represent items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Other includes a $656 million increase in securitized receivables under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. Significant changes in other items include an increase in under-recovered fuel primarily due to the deferral of fuel under the FAC in Ohio and higher fuel costs in Oklahoma, accrued tax benefits and the favorable impact of a decrease in fuel inventory. Deferred Income Taxes increased primarily due to a change in tax versus book temporary differences from operations. Accrued Taxes, Net increased primarily as a result of the receipt of a federal income tax refund of $419 million related to a net operating loss in 2009 that was carried back to 2007 and 2008. We also contributed $500 million to our qualified pension trust in 2010.

Net Cash Flows from Operating Activities were $2.5 billion in 2009 consisting primarily of Net Income of $1.4 billion and $1.6 billion of noncash Depreciation and Amortization. Other represents items that had a current period cash flow impact, such as changes in working capital, as well as items that represent future rights or obligations to receive or pay cash, such as regulatory assets and liabilities. Significant changes in other items include the negative impact on cash of an increase in coal inventory reflecting decreased customer demand for electricity, an increase in under-recovered fuel primarily in Ohio and West Virginia and an increase in accrued tax benefits resulting from a net income tax operating loss in 2009. Deferred Income Taxes increased primarily due to the American Recovery and Reinvestment Act of 2009 extending bonus depreciation provisions, a one-time change in tax accounting method and an increase in tax versus book temporary differences from operations.

Investing Activities

	Years Ended December 31,		
	2011	2010	2009
		(in millions)	
Construction Expenditures	$ (2,669)	$ (2,345)	$ (2,792)
Acquisitions of Nuclear Fuel	(106)	(91)	(169)
Acquisitions of Assets	(19)	(155)	(104)
Acquisitions of Cushion Gas from BOA	(214)	-	-
Proceeds from Sales of Assets	123	187	278
Other	(5)	(119)	(129)
Net Cash Flows Used for Investing Activities	$ (2,890)	$ (2,523)	$ (2,916)

Net Cash Flows Used for Investing Activities were $2.9 billion in 2011 primarily due to Construction Expenditures for new generation, environmental, distribution and transmission investments. We paid $214 million to BOA for cushion gas as part of a litigation settlement.

Net Cash Flows Used for Investing Activities were $2.5 billion in 2010 primarily due to Construction Expenditures for environmental, new generation, distribution and transmission investments. Proceeds from Sales of Assets in 2010 include $139 million for sales of Texas transmission assets to ETT.

Net Cash Flows Used for Investing Activities were $2.9 billion in 2009 primarily due to Construction Expenditures for our new generation, environmental, distribution and transmission investments. Proceeds from Sales of Assets in 2009 includes $104 million relating to the sale of a portion of Turk Plant to joint owners as planned and $95 million for sales of Texas transmission assets to ETT.

Financing Activities

	Years Ended December 31,		
	2011	2010	2009
		(in millions)	
Issuance of Common Stock, Net	$ 92	$ 93	$ 1,728
Issuance/Retirement of Debt, Net	(33)	497	(360)
Retirement of Cumulative Preferred Stock	(64)	-	-
Dividends Paid on Common Stock	(898)	(824)	(758)
Other	(68)	(101)	(90)
Net Cash Flows from (Used for) Financing Activities	$ (971)	$ (335)	$ 520

Net Cash Flows Used for Financing Activities in 2011 were $971 million. Our net debt retirements were $33 million. The net retirements included retirements of $727 million of senior unsecured and other debt notes, $778 million of pollution control bonds and $159 million of securitization bonds offset by issuances of $710 million of notes, $627 million of pollution control bonds and an increase in short-term borrowing of $304 million. We paid common stock dividends of $898 million and $64 million to retire all of our subsidiaries' preferred stocks. See Note 13 – Financing Activities.

Net Cash Flows Used for Financing Activities were $335 million in 2010. Our net debt issuances were $497 million. The net issuances included issuances of $952 million of notes and $326 million of pollution control bonds, a $531 million increase in commercial paper outstanding and retirements of $1.6 billion of notes, $148 million of securitization bonds and $222 million of pollution control bonds. Our short-term debt securitized by receivables increased $656 million under the application of new accounting guidance for "Transfers and Servicing" related to our sale of receivables agreement. We paid common stock dividends of $824 million.

Net Cash Flows from Financing Activities were $520 million in 2009. Issuance of Common Stock, Net of $1.7 billion is comprised of our issuance of 69 million shares of common stock with net proceeds of $1.64 billion and additional shares through our dividend reinvestment, employee savings and incentive programs. Our net debt retirements were $360 million. The net retirements included the repayment of $2 billion outstanding under our credit facilities and retirement of $816 million of long-term debt and issuances of $1.9 billion of senior unsecured and debt notes and $431 million of pollution control bonds. We paid common stock dividends of $758 million.

The following financing activities occurred during 2011:

AEP Common Stock:

- During 2011, we issued 2.6 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $92 million.

Preferred Stock of Subsidiaries:

- During 2011, we paid $64 million to retire all outstanding shares of our subsidiaries' preferred stock.

Debt:

- During 2011, we issued approximately $1.3 billion of long-term debt, including $600 million of senior notes at interest rates ranging from 4.4% to 4.6%. We also issued $627 million of pollution control revenue bonds, including $225 million at interest rates ranging from 1.125% to 2% and $402 million at variable interest rates. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2011, we entered into $975 million of interest rate derivatives and settled $974 million of such transactions. The settlements resulted in net cash receipts of $34 million. As of December 31, 2011, we had in place $907 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2012:

- In January 2012, TCC retired $98 million of its outstanding Securitization Bonds.
- In January and February 2012, I&M retired $14 million of Notes Payable related to DCC Fuel.
- In February 2012, APCo retired $30 million of 6.05% Pollution Control Bonds due in 2024 and $19.5 million of 5% Pollution Control Bonds due in 2021.
- In February 2012, SWEPCo issued $275 million of 3.55% Senior Unsecured Notes due in 2022 and $65 million of 4.58% Notes Payable due in 2032.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $3.1 billion of construction expenditures excluding equity AFUDC and capitalized interest for 2012. For 2013 and 2014, we forecast construction expenditures ranging from $3.4 billion to $3.5 billion each year. The projected increases are generally the result of required environmental investment to comply with Federal EPA rules and additional transmission spending. Estimated construction expenditures are subject to periodic review and modification and may vary based on the ongoing effects of regulatory constraints, environmental regulations, business opportunities, market volatility, economic trends, weather, legal reviews and the ability to access capital. We expect to fund these construction expenditures through cash flows from operations and financing activities. Generally, the subsidiaries use cash or short-term borrowings under the money pool to fund these expenditures until long-term funding is arranged. The estimated expenditures include amounts for completion of the Turk Plant. APCo's Dresden Plant was completed and placed in service in January 2012. SWEPCo's Turk Plant is expected to be in-service in the fourth quarter of 2012. The 2012 estimated construction expenditures include generation, transmission and distribution related investments, as well as expenditures for compliance with environmental regulations as follows:

	Budgeted Construction Expenditures
	(in millions)
Environmental	$ 511
Generation	781
Transmission	812
Distribution	847
Other	114
Total	$ 3,065

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including reducing operational expenses and spreading risk of loss to third parties. Our current guidelines restrict the use of off-balance sheet financing entities or structures to traditional operating lease arrangements that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements.

Rockport Plant Unit 2

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and certain institutional investors. The future minimum lease payments for AEGCo and I&M are $813 million and $813 million, respectively, as of December 31, 2011.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 12. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $34 million for the remaining railcars as of December 31, 2011. Under a return-and-sale option, the lessor is guaranteed that the sale proceeds will equal at least a specified lessee obligation amount which declines with each five-year renewal. At December 31, 2011, the maximum potential loss was approximately $25 million assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss. We have other railcar lease arrangements that do not utilize this type of financing structure.

CONTRACTUAL OBLIGATION INFORMATION

Our contractual cash obligations include amounts reported on the balance sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2011:

Payments Due by Period

Contractual Cash Obligations	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Short-term Debt (a)	$ 1,650	$ -	$ -	$ -	$ 1,650
Interest on Fixed Rate Portion of Long-term Debt (b)	788	1,402	1,169	6,382	9,741
Fixed Rate Portion of Long-term Debt (c)	888	2,346	2,202	10,457	15,893
Variable Rate Portion of Long-term Debt (d)	545	111	6	-	662
Capital Lease Obligations (e)	96	148	102	285	631
Noncancelable Operating Leases (e)	316	552	471	1,235	2,574
Fuel Purchase Contracts (f)	2,867	3,918	2,574	3,108	12,467
Energy and Capacity Purchase Contracts (g)	104	213	217	1,066	1,600
Construction Contracts for Capital Assets (h)	682	918	821	1,663	4,084
Total	$ 7,936	$ 9,608	$ 7,562	$ 24,196	$ 49,302

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2011 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 13. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 13. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.06% and 0.955% at December 31, 2011.
(e) See Note 12.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents contractual obligations for energy and capacity purchase contracts.
(h) Represents only capital assets for which we have signed contracts. Actual payments are dependent upon and may vary significantly based upon the decision to build, regulatory approval schedules, timing and escalation of project costs.

Our $68 million liability related to uncertainty in Income Taxes is not included above because we cannot reasonably estimate the cash flows by period.

Our pension funding requirements are not included in the above table. As of December 31, 2011, we expect to make contributions to our pension plans totaling $208 million in 2012. Estimated contributions of $107 million in 2013 and $107 million in 2014 may vary significantly based on market returns, changes in actuarial assumptions and other factors. Based upon the benefit obligation and fair value of assets available to pay pension benefits, our pension plans were 86.2% funded as of December 31, 2011.

In addition to the amounts disclosed in the contractual cash obligations table above, we make additional commitments in the normal course of business. These commitments include standby letters of credit, guarantees for the payment of obligation performance bonds and other commitments. At December 31, 2011, our commitments outstanding under these agreements are summarized in the table below:

Amount of Commitment Expiration Per Period

Other Commercial Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Standby Letters of Credit (a)	$ 134	$ -	$ -	$ -	$ 134
Guarantees of the Performance of Outside Parties (b)	-	-	-	100	100
Guarantees of Our Performance (c)	402	7	20	36	465
Total Commercial Commitments	$ 536	$ 7	$ 20	$ 136	$ 699

(a) We enter into standby letters of credit (LOCs) with third parties. These LOCs cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves. AEP, on behalf of our subsidiaries, and/or the subsidiaries issued all of these LOCs in the ordinary course of business. There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any LOC is drawn, there is no recourse to third parties. The maximum future payments of these LOCs are $134 million with maturities ranging from January 2012 to October 2012. Subsequent to December 31, 2011, standby LOCs have increased approximately $100 million as a result of declining market prices related to our risk management contracts. This increase is partially offset by a reduction of posted cash collateral of approximately $20 million. See "Letters of Credit" section of Note 5.

(b) See "Guarantees of Third-Party Obligations" section of Note 5.

(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs, expanded tax credits and extended the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The Small Business Jobs Act, enacted in September 2010, included a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, this act extended the time for claiming bonus depreciation and increased the deduction to 100% starting in September 2010 through 2011 and decreasing the deduction to 50% for 2012.

These enacted provisions did not have a material impact on net income or financial condition but had a favorable impact on cash flows in 2010 and 2011 and are expected to result in material future cash flow benefits in 2012.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES, NEW ACCOUNTING PRONOUNCEMENTS

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The preparation of financial statements in accordance with GAAP requires us to make estimates and assumptions that affect reported amounts and related disclosures, including amounts related to legal matters and contingencies. We consider an accounting estimate to be critical if:

- It requires assumptions to be made that were uncertain at the time the estimate was made; and
- Changes in the estimate or different estimates that could have been selected could have a material effect on our consolidated net income or financial condition.

We discuss the development and selection of critical accounting estimates as presented below with the Audit Committee of AEP's Board of Directors and the Audit Committee reviews the disclosure relating to them.

We believe that the current assumptions and other considerations used to estimate amounts reflected in our consolidated financial statements are appropriate. However, actual results can differ significantly from those estimates.

The sections that follow present information about our critical accounting estimates, as well as the effects of hypothetical changes in the material assumptions used to develop each estimate.

Regulatory Accounting

Nature of Estimates Required

Our financial statements reflect the actions of regulators that can result in the recognition of revenues and expenses in different time periods than enterprises that are not rate-regulated.

We recognize regulatory assets (deferred expenses to be recovered in the future) and regulatory liabilities (deferred future revenue reductions or refunds) for the economic effects of regulation. Specifically, we match the timing of expense and income recognition with regulated revenues. We also record liabilities for refunds, or probable refunds, to customers that have not been made.

Assumptions and Approach Used

When incurred costs are probable of recovery through regulated rates, we record them as regulatory assets on the balance sheet. We review the probability of recovery at each balance sheet date and whenever new events occur. Similarly, we record regulatory liabilities when a determination is made that a refund is probable or when ordered by a commission. Examples of new events that affect probability include changes in the regulatory environment, issuance of a regulatory commission order or passage of new legislation. The assumptions and judgments used by regulatory authorities continue to have an impact on the recovery of costs as well as the return of revenues, rate of return earned on invested capital and timing and amount of assets to be recovered through regulated rates. If recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against earnings. A write-off of regulatory assets or establishment of a regulatory liability may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 4 for further detail related to regulatory assets and liabilities.

Revenue Recognition – Unbilled Revenues

Nature of Estimates Required

We record revenues when energy is delivered to the customer. The determination of sales to individual customers is based on the reading of their meters, which we perform on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue accrual is recorded. This estimate is reversed in the following month and actual revenue is recorded based on meter readings. In accordance with the applicable state commission regulatory treatment in Arkansas, Louisiana, Oklahoma and Texas, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

The changes in unbilled electric utility revenues included in Revenue on our statements of income were $(81) million, $46 million and $55 million for the years ended December 31, 2011, 2010 and 2009, respectively. The changes in unbilled electric revenues are primarily due to changes in weather and rate increases. Accrued unbilled revenues for the Utility Operations segment were $468 million and $549 million as of December 31, 2011 and 2010, respectively.

Assumptions and Approach Used

For each operating company, we compute the monthly estimate for unbilled revenues as net generation less the current month's billed KWH plus the prior month's unbilled KWH. However, due to meter reading issues, meter drift and other anomalies, a separate monthly calculation limits the unbilled estimate within a range of values. This limiter calculation is derived from an allocation of billed KWH to the current month and previous month, on a cycle-by-cycle basis, and by dividing the current month aggregated result by the billed KWH. The limits are statistically set at one standard deviation from this percentage to determine the upper and lower limits of the range. The unbilled estimate is compared to the limiter calculation and adjusted for variances exceeding the upper and lower limits.

Effect if Different Assumptions Used

Significant fluctuations in energy demand for the unbilled period, weather, line losses or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. A 1% change in the limiter calculation when it is outside the range would increase or decrease unbilled revenues by 1% of the accrued unbilled revenues.

Accounting for Derivative Instruments

Nature of Estimates Required

We consider fair value techniques, valuation adjustments related to credit and liquidity and judgments related to the probability of forecasted transactions occurring within the specified time period to be critical accounting estimates. These estimates are considered significant because they are highly susceptible to change from period to period and are dependent on many subjective factors.

Assumptions and Approach Used

We measure the fair values of derivative instruments and hedge instruments accounted for using MTM accounting based on exchange prices and broker quotes. If a quoted market price is not available, we estimate the fair value based on the best market information available including valuation models that estimate future energy prices based on existing market and broker quotes, supply and demand market data and other assumptions. Fair value estimates, based upon the best market information available, involve uncertainties and matters of significant judgment. These uncertainties include projections of macroeconomic trends and future commodity prices, including supply and demand levels and future price volatility.

We reduce fair values by estimated valuation adjustments for items such as discounting, liquidity and credit quality. We calculate liquidity adjustments by utilizing bid/ask spreads to estimate the potential fair value impact of liquidating open positions over a reasonable period of time. We calculate credit adjustments on our risk management contracts using estimated default probabilities and recovery rates relative to our counterparties or counterparties with similar credit profiles and contractual netting agreements.

With respect to hedge accounting, we assess hedge effectiveness and evaluate a forecasted transaction's probability of occurrence within the specified time period as provided in the original hedge documentation.

Effect if Different Assumptions Used

There is inherent risk in valuation modeling given the complexity and volatility of energy markets. Therefore, it is possible that results in future periods may be materially different as contracts settle.

The probability that hedged forecasted transactions will not occur by the end of the specified time period could change operating results by requiring amounts currently classified in Accumulated Other Comprehensive Income (Loss) to be classified into operating income.

For additional information regarding derivatives, hedging and fair value measurements, see Notes 9 and 10. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable including planned abandonments and a probable disallowance for rate-making on a plant under construction or the assets meet the held-for-sale criteria. We utilize a group composite method of depreciation to estimate the useful lives of long-lived assets. The evaluations of long-lived, held-and-used assets may result from abandonments, significant decreases in the market price of an asset, a significant adverse change in the extent or manner in which an asset is being used or in its physical condition, a significant adverse change in legal factors or in the business climate that could affect the value of an asset, as well as other economic or operations analyses. If the carrying amount is not recoverable, we record an impairment to the extent that the fair value of the asset is less than its book value. For assets held for sale, an impairment is recognized if the expected net sales price is less than its book value. For regulated assets, the earnings impact of an impairment charge could be offset by the establishment of a regulatory asset if rate recovery is probable. For nonregulated assets, any impairment charge is recorded against earnings.

Assumptions and Approach Used

The fair value of an asset is the amount at which that asset could be bought or sold in a current transaction between willing parties other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods including cash flow projections or other market indicators of fair value such as bids received, comparable sales or independent appraisals. We perform depreciation studies that include a review of any external factors that may affect the useful life to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions for cost-based regulated assets. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of an asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of deductible amounts as permitted under the provisions of the tax law to be paid to participants in the Qualified Plan (collectively the Pension Plans). Additionally, we entered into individual employment contracts with certain current and retired executives that provide additional retirement benefits as a part of the Nonqualified Plans. We also sponsor other postretirement benefit plans to provide medical and life insurance benefits for retired employees (Postretirement Plans). The Pension Plans and Postretirement Plans are collectively the Plans.

For a discussion of investment strategy, investment limitations, target asset allocations and the classification of investments within the fair value hierarchy, see "Investments Held in Trust for Future Liabilities" and "Fair Value Measurements of Assets and Liabilities" sections of Note 1. See Note 7 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost of the Plans:

Net Periodic Benefit Cost	Years Ended December 31, 2011	2010	2009
		(in millions)	
Pension Plans	$ 118	$ 141	$ 96
Postretirement Plans	73	111	141

The net periodic benefit cost is calculated based upon a number of actuarial assumptions, including expected long-term rates of return on the Plans' assets. In developing the expected long-term rate of return assumption for 2012, we evaluated input from actuaries and investment consultants, including their reviews of asset class return expectations as well as long-term inflation assumptions. We also considered historical returns of the investment markets. We anticipate that the investment managers we employ for the Plans will invest the assets to generate future returns averaging 7.25%.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension Plans		Other Postretirement Benefit Plans	
	2012 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return	2012 Target Asset Allocation	Assumed/ Expected Long-Term Rate of Return
Equity	45 %	8.75 %	66 %	8.50 %
Fixed Income	45 %	5.25 %	33 %	5.08 %
Other Investments	10 %	8.75 %	-%	- %
Cash and Cash Equivalents	-%	-%	1 %	1.55 %
Total	100 %		100 %	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 7.25% is a reasonable estimate of the long-term rate of return on the Plans' assets despite the recent market volatility. The Pension Plans' assets had an actual gain of 8.1% and 13.4% for the years ended December 31, 2011 and 2010, respectively. The Postretirement Plans' assets had an actual gain of 0.4% and 11.3% for the years ended December 31, 2011 and 2010, respectively. We will continue to evaluate the actuarial assumptions, including the expected rate of return, at least annually, and will adjust the assumptions as necessary.

We base our determination of pension expense or income on a market-related valuation of assets, which reduces year-to-year volatility. This market-related valuation recognizes investment gains or losses over a five-year period from the year in which they occur. Investment gains or losses for this purpose are the difference between the expected return calculated using the market-related value of assets and the actual return based on the market-related value of assets. Since the market-related value of assets recognizes gains or losses over a five-year period, the future value of assets will be impacted as previously deferred gains or losses are recorded. As of December 31, 2011, we had cumulative losses of approximately $104 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses may result in increases in the future pension costs depending on several factors, including whether such losses at each measurement date exceed the corridor in accordance with "Compensation – Retirement Benefits" accounting guidance.

The method used to determine the discount rate that we utilize for determining future obligations is a duration-based method in which a hypothetical portfolio of high quality corporate bonds 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. The discount rate at December 31, 2011 under this method was 4.55% for the Qualified Plan, 4.4% for the Nonqualified Plans and 4.75% for the Postretirement Plans. Due to the effect of the unrecognized actuarial losses and based on an expected rate of return on the Pension Plans' assets of 7.25%, discount rates of 4.55% and 4.4% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $127 million, $150 million and $125 million in 2012, 2013 and 2014, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 7.25%, a discount rate of 4.75% and various other assumptions, we estimate costs will approximate $95 million, $88 million and $81 million in 2012, 2013 and 2014, respectively. Future actual costs will depend on future investment performance, changes in future discount rates and various other factors related to the populations participating in the Plans. The actuarial assumptions used may differ materially from actual results. The effects of a 50 basis point change to selective actuarial assumptions are included in the "Effect if Different Assumptions Used" section below.

The value of the Pension Plans' assets increased to $4.3 billion at December 31, 2011 from $3.9 billion at December 31, 2010 primarily due to $450 million of contributions. During 2011, the Qualified Plan paid $287 million and the Nonqualified Plans paid $7 million in benefits to plan participants. The value of the Postretirement Plans' assets decreased to $1.4 billion at December 31, 2011 from $1.5 billion at December 31, 2010 primarily due to benefits paid exceeding contributions by the company and the participants. The Postretirement Plans paid $150 million in benefits to plan participants during 2011.

Nature of Estimates Required

We sponsor pension and other retirement and postretirement benefit plans in various forms covering all employees who meet eligibility requirements. We account for these benefits under "Compensation" and "Plan Accounting" accounting guidance. The measurement of our pension and postretirement benefit obligations, costs and liabilities is dependent on a variety of assumptions.

Assumptions and Approach Used

The critical assumptions used in developing the required estimates include the following key factors:

- Discount rate
- Compensation increase rate
- Cash balance crediting rate
- Health care cost trend rate
- Expected return on plan assets

Other assumptions, such as retirement, mortality and turnover, are evaluated periodically and updated to reflect actual experience.

Effect if Different Assumptions Used

The actuarial assumptions used may differ materially from actual results due to changing market and economic conditions, higher or lower withdrawal rates, longer or shorter life spans of participants or higher or lower lump sum versus annuity payout elections by plan participants. These differences may result in a significant impact to the amount of pension and postretirement benefit expense recorded. If a 50 basis point change were to occur for the following assumptions, the approximate effect on the financial statements would be as follows:

	Pension Plans		Other Postretirement Benefit Plans	
	+0.5%	-0.5%	+0.5%	-0.5%
	(in millions)			
Effect on December 31, 2011 Benefit Obligations				
Discount Rate	$ (256)	$ 281	$ (142)	$ 159
Compensation Increase Rate	11	(10)	-	-
Cash Balance Crediting Rate	45	(40)	NA	NA
Health Care Cost Trend Rate	NA	NA	120	(109)
Effect on 2011 Periodic Cost				
Discount Rate	(18)	19	(11)	12
Compensation Increase Rate	4	(4)	-	-
Cash Balance Crediting Rate	13	(12)	NA	NA
Health Care Cost Trend Rate	NA	NA	18	(16)
Expected Return on Plan Assets	(20)	20	(7)	7

NA Not Applicable

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2011

We adopted ASU 2011-5 "Presentation of Comprehensive Income" effective for the 2011 Annual Report including the deferral of the reclassification adjustment presentation provisions of ASU 2011-05 under the terms in ASU 2011-12, "Comprehensive Income (Topic 220): Deferral of the Effective Date for Amendments to the Presentation of Reclassifications of Items Out of Accumulated Other Comprehensive Income." The standard requires other comprehensive income be presented as part of a single continuous statement of comprehensive income or in a statement of other comprehensive income immediately following the statement of net income. This standard changed the presentation of our financial statements but did not affect the calculation of net income, comprehensive income or earnings per share.

See Note 2 for further discussion of accounting pronouncements.

Future Accounting Changes

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

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and through its transactions in wholesale electricity, coal and emission allowance trading and marketing contracts. These risks include commodity price risk, interest rate risk and credit risk. In addition, we are exposed to foreign currency exchange risk because occasionally we procure various services and materials used in our energy business from foreign suppliers. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

Our Generation and Marketing segment primarily transacts in wholesale energy marketing within ERCOT and, to a lesser extent, wholesale and retail energy contracts in Ohio within PJM and MISO. This segment is exposed to certain market risks as a marketer of wholesale and retail electricity. These risks include commodity price risk, interest rate risk and credit risk. These risks represent the risk of loss that may impact us due to changes in the underlying market prices or rates.

All Other included natural gas operations which held forward natural gas contracts that were not sold with the natural gas pipeline and storage assets. These contracts were financial derivatives, which settled and expired in the fourth quarter of 2011.

We employ risk management contracts including physical forward purchase and sale contracts and financial forward purchase and sale contracts. We engage in risk management of power, coal and natural gas and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. As a result, we are subject to price risk. The amount of risk taken is determined by the commercial operations group in accordance with the market risk policy approved by the Finance Committee of our Board of Directors. Our market risk oversight staff independently monitors our risk policies, procedures and risk levels and provides members of the Commercial Operations Risk Committee (CORC) various daily, weekly and/or monthly reports regarding compliance with policies, limits and procedures. The CORC consists of our Chief Operating Officer, Chief Financial Officer, Senior Vice President of Commercial Operations and Chief Risk Officer. When commercial activities exceed predetermined limits, we modify the positions to reduce the risk to be within the limits unless specifically approved by the CORC.

The following table summarizes the reasons for changes in total mark-to-market (MTM) value as compared to December 31, 2010:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2011

	Utility Operations	Generation and Marketing	All Other	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets at December 31, 2010	$ 91	$ 140	$ 2	$ 233
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(21)	(22)	(2)	(45)
Fair Value of New Contracts at Inception When Entered During the Period (a)	6	16	-	22
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	-	-	-	-
Changes in Fair Value Due to Market Fluctuations During the Period (b)	-	(2)	-	(2)
Changes in Fair Value Allocated to Regulated Jurisdictions (c)	(17)	-	-	(17)
Total MTM Risk Management Contract Net Assets at December 31, 2011	$ 59	$ 132	$ -	191
Commodity Cash Flow Hedge Contracts				(5)
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				(42)
Fair Value Hedge Contracts				-
Collateral Deposits				107
Total MTM Derivative Contract Net Assets at December 31, 2011				$ 251

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(c) Relates to the net gains (losses) of those contracts that are not reflected on the statements of income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 9 – Derivatives and Hedging and Note 10 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2011, our credit exposure net of collateral to sub investment grade counterparties was approximately 5.9%, expressed in terms of net MTM assets, net receivables and the net open positions for contracts not subject to MTM (representing economic risk even though there may not be risk of accounting loss). As of December 31, 2011, the following table approximates our counterparty credit quality and exposure based on netting across commodities, instruments and legal entities where applicable:

Counterparty Credit Quality	Exposure Before Credit Collateral	Credit Collateral	Net Exposure	Number of Counterparties >10% of Net Exposure	Net Exposure of Counterparties >10%
	(in millions, except number of counterparties)				
Investment Grade	$ 611	$ 2	$ 609	1	$ 172
Split Rating	1	-	1	1	1
Noninvestment Grade	14	2	12	1	12
No External Ratings:					
Internal Investment Grade	280	4	276	1	128
Internal Noninvestment Grade	54	11	43	1	35
Total as of December 31, 2011	$ 960	$ 19	$ 941	5	$ 348
Total as of December 31, 2010	$ 946	$ 33	$ 913	7	$ 347

Value at Risk (VaR) Associated with Risk Management Contracts

We use a risk measurement model, which calculates VaR, to measure our commodity price risk in the risk management portfolio. The VaR is based on the variance-covariance method using historical prices to estimate volatilities and correlations and assumes a 95% confidence level and a one-day holding period. Based on this VaR analysis, as of December 31, 2011, a near term typical change in commodity prices is not expected to have a material effect on our net income, cash flows or financial condition.

The following table shows the end, high, average and low market risk as measured by VaR for the trading portfolio for the periods indicated:

VaR Model

Twelve Months Ended December 31, 2011				Twelve Months Ended December 31, 2010			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$ -	$ 2	$ -	$ -	$ -	$ 2	$ 1	$ -

We back-test our VaR results against performance due to actual price movements. Based on the assumed 95% confidence interval, the performance due to actual price movements would be expected to exceed the VaR at least once every 20 trading days.

As our VaR calculation captures recent price movements, we also perform regular stress testing of the portfolio to understand our exposure to extreme price movements. We employ a historical-based method whereby the current portfolio is subjected to actual, observed price movements from the last four years in order to ascertain which historical price movements translated into the largest potential MTM loss. We then research the underlying positions, price movements and market events that created the most significant exposure and report the findings to the Risk Executive Committee or the CORC as appropriate.

Interest Rate Risk

We utilize an Earnings at Risk (EaR) model to measure interest rate market risk exposure. EaR statistically quantifies the extent to which our interest expense could vary over the next twelve months and gives a probabilistic estimate of different levels of interest expense. The resulting EaR is interpreted as the dollar amount by which actual interest expense for the next twelve months could exceed expected interest expense with a one-in-twenty chance of occurrence. The primary drivers of EaR are from the existing floating rate debt (including short-term debt) as well as long-term debt issuances in the next twelve months. As calculated on debt outstanding as of December 31, 2011 and 2010, the estimated EaR on our debt portfolio for the following twelve months was $29 million and $5 million, respectively.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the accompanying consolidated balance sheets of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2011 and 2010, and the related consolidated statements of income, comprehensive income (loss), changes in equity, and cash flows for each of the three years in the period ended December 31, 2011. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of American Electric Power Company, Inc. and subsidiary companies as of December 31, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, in 2011 the Company changed its method of presenting comprehensive income due to the adoption of FASB Accounting Standards Update No. 2011-05, *Comprehensive Income (Topic 220): Presentation of Comprehensive Income.* The change in presentation has been applied retrospectively to all periods presented. As discussed in Note 2 to the consolidated financial statements, on January 1, 2010, the Company adopted FASB Accounting Standards Update No. 2009-16, *Transfers and Servicing (Topic 860): Accounting for Transfers of Financial Assets.*

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholders of American Electric Power Company, Inc.:

We have audited the internal control over financial reporting of American Electric Power Company, Inc. and subsidiary companies (the "Company") as of December 31, 2011, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying *Management's Report on Internal Control Over Financial Reporting*. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed by, or under the supervision of, the company's principal executive and principal financial officers, or persons performing similar functions, and effected by the company's board of directors, management, and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2011, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements as of and for the year ended December 31, 2011 of the Company and our report dated February 28, 2012 expressed an unqualified opinion on those financial statements and included an explanatory paragraph relating to the Company's adoption of new accounting pronouncements in 2011 and 2010.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 28, 2012

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of American Electric Power Company, Inc. and subsidiary companies (AEP) is responsible for establishing and maintaining adequate internal control over financial reporting as such term is defined in Rule 13a-15(f) and 15d-15(f) under the Securities Exchange Act of 1934, as amended. AEP's internal control system was designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Management assessed the effectiveness of AEP's internal control over financial reporting as of December 31, 2011. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in Internal Control – Integrated Framework. Based on management's assessment, AEP's internal control over financial reporting was effective as of December 31, 2011.

AEP's independent registered public accounting firm has issued an attestation report on AEP's internal control over financial reporting. The Report of Independent Registered Public Accounting Firm appears on the previous page.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF INCOME
For the Years Ended December 31, 2011, 2010 and 2009
(in millions, except per-share and share amounts)

	2011	2010	2009
REVENUES			
Utility Operations	$ 14,091	$ 13,687	$ 12,733
Other Revenues	1,025	740	756
TOTAL REVENUES	15,116	14,427	13,489
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,421	4,029	3,478
Purchased Electricity for Resale	1,191	1,000	1,053
Other Operation	2,868	3,132	2,620
Maintenance	1,236	1,142	1,205
Asset Impairments and Other Related Charges	139	-	-
Depreciation and Amortization	1,655	1,641	1,597
Taxes Other Than Income Taxes	824	820	765
TOTAL EXPENSES	12,334	11,764	10,718
OPERATING INCOME	2,782	2,663	2,771
Other Income (Expense):			
Interest and Investment Income	27	38	11
Carrying Costs Income	393	70	47
Allowance for Equity Funds Used During Construction	98	77	82
Interest Expense	(933)	(999)	(973)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	2,367	1,849	1,938
Income Tax Expense	818	643	575
Equity Earnings of Unconsolidated Subsidiaries	27	12	7
INCOME BEFORE EXTRAORDINARY ITEMS	1,576	1,218	1,370
EXTRAORDINARY ITEMS, NET OF TAX	373	-	(5)
NET INCOME	1,949	1,218	1,365
Net Income Attributable to Noncontrolling Interests	3	4	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,946	1,214	1,360
Preferred Stock Dividend Requirements of Subsidiaries Including Capital Stock Expense	5	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,941	$ 1,211	$ 1,357
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	482,169,282	479,373,306	458,677,534
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Items	$ 3.25	$ 2.53	$ 2.97
Extraordinary Items, Net of Tax	0.77	-	(0.01)
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.02	$ 2.53	$ 2.96
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	482,460,328	479,601,442	458,982,292
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Extraordinary Items	$ 3.25	$ 2.53	$ 2.97
Extraordinary Items, Net of Tax	0.77	-	(0.01)
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 4.02	$ 2.53	$ 2.96
CASH DIVIDENDS DECLARED PER SHARE	$ 1.85	$ 1.71	$ 1.64

See Notes to Consolidated Financial Statements beginning on page 52.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	2011	2010	2009
NET INCOME	$ 1,949	$ 1,218	$ 1,365
OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAXES			
Cash Flow Hedges, Net of Tax of $18 in 2011, $14 in 2010 and $4 in 2009	(34)	26	7
Securities Available for Sale, Net of Tax of $1 in 2011, $4 in 2010 and $6 in 2009	(2)	(8)	11
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8 in 2009	-	-	15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $13 in 2011, $12 in 2010 and $13 in 2009	24	22	23
Pension and OPEB Funded Status, Net of Tax of $41 in 2011, $25 in 2010 and $12 in 2009	(77)	(47)	22
TOTAL OTHER COMPREHENSIVE INCOME (LOSS)	(89)	(7)	78
TOTAL COMPREHENSIVE INCOME	1,860	1,211	1,443
Total Comprehensive Income Attributable to Noncontrolling Interests	3	4	5
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,857	1,207	1,438
Preferred Stock Dividend Requirements Including Capital Stock Expense	5	3	3
TOTAL COMPREHENSIVE INCOME ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,852	$ 1,204	$ 1,435

See Notes to Consolidated Financial Statements beginning on page 52.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	AEP Common Shareholders						
	Common Stock						
	Shares	Amount	Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interests	Total
TOTAL EQUITY – DECEMBER 31, 2008	426	$ 2,771	$ 4,527	$ 3,847	$ (452)	$ 17	$ 10,710
Issuance of Common Stock	72	468	1,311				1,779
Common Stock Dividends				(753)		(5)	(758)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Purchase of JMG			37			(18)	19
Other Changes in Equity			(51)			1	(50)
SUBTOTAL – EQUITY							11,697
NET INCOME				1,360		5	1,365
OTHER COMPREHENSIVE INCOME					78		78
TOTAL EQUITY – DECEMBER 31, 2009	498	3,239	5,824	4,451	(374)	-	13,140
Issuance of Common Stock	3	18	75				93
Common Stock Dividends				(820)		(4)	(824)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			5				5
SUBTOTAL – EQUITY							12,411
NET INCOME				1,214		4	1,218
OTHER COMPREHENSIVE LOSS					(7)		(7)
TOTAL EQUITY – DECEMBER 31, 2010	501	3,257	5,904	4,842	(381)	-	13,622
Issuance of Common Stock	3	17	75				92
Common Stock Dividends				(894)		(4)	(898)
Preferred Stock Dividend Requirements of Subsidiaries				(2)			(2)
Loss on Reacquired Preferred Stock			(4)				(4)
Capital Stock Expense			(16)				(16)
Other Changes in Equity			11	(2)		2	11
SUBTOTAL – EQUITY							12,805
NET INCOME				1,946		3	1,949
OTHER COMPREHENSIVE LOSS					(89)		(89)
TOTAL EQUITY – DECEMBER 31, 2011	504	$ 3,274	$ 5,970	$ 5,890	$ (470)	$ 1	$ 14,665

See Notes to Consolidated Financial Statements beginning on page 52.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2011 and 2010
(in millions)

	2011	2010
CURRENT ASSETS		
Cash and Cash Equivalents	$ 221	$ 294
Other Temporary Investments (December 31, 2011 and 2010 amounts include $281 and $287, respectively, related to Transition Funding and EIS)	294	416
Accounts Receivable:		
Customers	690	683
Accrued Unbilled Revenues	106	195
Pledged Accounts Receivable - AEP Credit	920	949
Miscellaneous	150	137
Allowance for Uncollectible Accounts	(32)	(41)
Total Accounts Receivable	1,834	1,923
Fuel	657	837
Materials and Supplies	635	611
Risk Management Assets	193	232
Accrued Tax Benefits	51	389
Regulatory Asset for Under-Recovered Fuel Costs	65	81
Margin Deposits	67	88
Prepayments and Other Current Assets	165	145
TOTAL CURRENT ASSETS	4,182	5,016
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,938	24,352
Transmission	9,048	8,576
Distribution	14,783	14,208
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	3,780	3,846
Construction Work in Progress	3,121	2,758
Total Property, Plant and Equipment	55,670	53,740
Accumulated Depreciation and Amortization	18,699	18,066
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	36,971	35,674
OTHER NONCURRENT ASSETS		
Regulatory Assets	6,026	4,943
Securitized Transition Assets	1,627	1,742
Spent Nuclear Fuel and Decommissioning Trusts	1,592	1,515
Goodwill	76	76
Long-term Risk Management Assets	403	410
Deferred Charges and Other Noncurrent Assets	1,346	1,079
TOTAL OTHER NONCURRENT ASSETS	11,070	9,765
TOTAL ASSETS	$ 52,223	$ 50,455

See Notes to Consolidated Financial Statements beginning on page 52.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2011 and 2010
(dollars in millions)

		2011		2010
CURRENT LIABILITIES				
Accounts Payable	$	1,095	$	1,061
Short-term Debt:				
Securitized Debt for Receivables - AEP Credit		666		690
Other Short-term Debt		984		656
Total Short-term Debt		1,650		1,346
Long-term Debt Due Within One Year (December 31, 2011 and 2010 amounts include $293 and $237, respectively, related to Transition Funding, DCC Fuel and Sabine)		1,433		1,309
Risk Management Liabilities		150		129
Customer Deposits		289		273
Accrued Taxes		717		702
Accrued Interest		279		281
Regulatory Liability for Over-Recovered Fuel Costs		8		17
Deferred Gain and Accrued Litigation Costs		-		448
Other Current Liabilities		990		952
TOTAL CURRENT LIABILITIES		6,611		6,518
NONCURRENT LIABILITIES				
Long-term Debt (December 31, 2011 and 2010 amounts include $1,674 and $1,857, respectively, related to Transition Funding, DCC Fuel and Sabine)		15,083		15,502
Long-term Risk Management Liabilities		195		141
Deferred Income Taxes		8,227		7,359
Regulatory Liabilities and Deferred Investment Tax Credits		3,195		3,171
Asset Retirement Obligations		1,472		1,394
Employee Benefits and Pension Obligations		1,801		1,893
Deferred Credits and Other Noncurrent Liabilities		974		795
TOTAL NONCURRENT LIABILITIES		30,947		30,255
TOTAL LIABILITIES		37,558		36,773
Cumulative Preferred Stock Not Subject to Mandatory Redemption		-		60
Rate Matters (Note 3)				
Commitments and Contingencies (Note 5)				
EQUITY				
Common Stock – Par Value – $6.50 Per Share:				
Shares Authorized: 2011 600,000,000; 2010 600,000,000				
Shares Issued: 2011 503,759,460; 2010 501,114,881				
(20,336,592 shares and 20,307,725 shares were held in treasury at December 31, 2011 and 2010, respectively)		3,274		3,257
Paid-in Capital		5,970		5,904
Retained Earnings		5,890		4,842
Accumulated Other Comprehensive Income (Loss)		(470)		(381)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY		14,664		13,622
Noncontrolling Interests		1		-
TOTAL EQUITY		14,665		13,622
TOTAL LIABILITIES AND EQUITY	$	52,223	$	50,455

See Notes to Consolidated Financial Statements beginning on page 52.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	2011	2010	2009
OPERATING ACTIVITIES			
Net Income	$ 1,949	$ 1,218	$ 1,365
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,655	1,641	1,597
Deferred Income Taxes	794	809	1,244
Gain on Settlement with BOA and Enron	(51)	-	-
Settlement of Litigation with BOA and Enron	(211)	-	-
Extraordinary Items, Net of Tax	(373)	-	5
Asset Impairments and Other Related Charges	139	-	-
Carrying Costs Income	(393)	(70)	(47)
Allowance for Equity Funds Used During Construction	(98)	(77)	(82)
Mark-to-Market of Risk Management Contracts	37	30	(59)
Amortization of Nuclear Fuel	137	139	63
Pension Contributions to Qualified Plan Trust	(450)	(500)	-
Property Taxes	(15)	(21)	(17)
Fuel Over/Under-Recovery, Net	(25)	(253)	(474)
Change in Other Noncurrent Assets	(112)	(89)	(152)
Change in Other Noncurrent Liabilities	307	202	244
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	107	(866)	41
Fuel, Materials and Supplies	176	221	(475)
Accounts Payable	(44)	(36)	8
Accrued Taxes, Net	193	179	(470)
Other Current Assets	37	73	(73)
Other Current Liabilities	29	62	(243)
Net Cash Flows from Operating Activities	3,788	2,662	2,475
INVESTING ACTIVITIES			
Construction Expenditures	(2,669)	(2,345)	(2,792)
Change in Other Temporary Investments, Net	8	(4)	16
Purchases of Investment Securities	(1,321)	(1,918)	(853)
Sales of Investment Securities	1,379	1,817	748
Acquisitions of Nuclear Fuel	(106)	(91)	(169)
Acquisitions of Assets	(19)	(155)	(104)
Acquisition of Cushion Gas from BOA	(214)	-	-
Proceeds from Sales of Assets	123	187	278
Other Investing Activities	(71)	(14)	(40)
Net Cash Flows Used for Investing Activities	(2,890)	(2,523)	(2,916)
FINANCING ACTIVITIES			
Issuance of Common Stock, Net	92	93	1,728
Issuance of Long-term Debt	1,328	1,270	2,306
Commercial Paper and Credit Facility Borrowings	488	565	127
Change in Short-term Debt, Net	744	770	119
Retirement of Long-term Debt	(1,665)	(1,993)	(816)
Retirement of Cumulative Preferred Stock	(64)	-	-
Commercial Paper and Credit Facility Repayments	(928)	(115)	(2,096)
Principal Payments for Capital Lease Obligations	(71)	(95)	(82)
Dividends Paid on Common Stock	(898)	(824)	(758)
Dividends Paid on Cumulative Preferred Stock	(2)	(3)	(3)
Other Financing Activities	5	(3)	(5)
Net Cash Flows from (Used for) Financing Activities	(971)	(335)	520
Net Increase (Decrease) in Cash and Cash Equivalents	(73)	(196)	79
Cash and Cash Equivalents at Beginning of Period	294	490	411
Cash and Cash Equivalents at End of Period	$ 221	$ 294	$ 490

See Notes to Consolidated Financial Statements beginning on page 52.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS