FORM DEF 14A

Definitive proxy statements

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SCHEDULE 14A
(Rule 14a-101)
INFORMATION REQUIRED IN PROXY STATEMENT
SCHEDULE 14A INFORMATION
Proxy Statement Pursuant to Section 14(a) of the Securities Exchange Act of 1934
(Amendment No.)

Filed by the Registrant ☒

Filed by a Party other than the Registrant ☐

Check the appropriate box:

☐ Preliminary Proxy Statement

☐ **Confidential, for Use of the Commission Only (as permitted by Rule 14a-6(e)(2))**

☒ Definitive Proxy Statement

☐ Definitive Additional Materials

☐ Soliciting Material Pursuant to Rule 14a-12.

American Electric Power Company, Inc.

(Name of Registrant as Specified in its Charter)

(Name of Person(s) Filing Proxy Statement, if other than the Registrant)

Payment of Filing Fee (Check the appropriate box):

☒ No fee required.

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(1) Amount Previously Paid:

(2) Form, Schedule or Registration Statement No.:

(3) Filing Party:

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Notice of 2011 Annual Meeting   Proxy Statement

American Electric Power
1 Riverside Plaza
Columbus, OH 43215

Michael G. Morris
Chairman of the Board
and
Chief Executive Officer

March 14, 2011

Dear Shareholder:

This year' s annual meeting of shareholders will be held at The Ohio State University' s Fawcett Center, 2400 Olentangy River Road, Columbus, Ohio, on Tuesday, April 26, 2011, at 9:30 a.m. Eastern Time.

Your Board of Directors and I cordially invite you to attend. Registration will begin at 8:00 a.m. Only shareholders who owned shares on the record date, February 28, 2011, are entitled to vote and attend the meeting. To attend the meeting, you will need to present an admission ticket or the notice you received. If your shares are registered in your name, and you received your proxy materials by mail, your admission ticket is attached to your proxy card. A map and directions are printed on the admission ticket. If your shares are registered in your name and you received your proxy materials electronically via the internet, you will need to print an admission ticket after you vote by clicking on the "Options" button. If you hold shares through an account with a bank or broker, you will need to contact them and request a legal proxy, or bring a copy of your statement to the meeting that shows that you owned the shares on the record date. Each ticket will admit a shareholder and one guest.

This year, we again are pleased to be using the U.S. Securities and Exchange Commission rule that allows companies to furnish their proxy materials over the Internet. As a result, we are mailing to many of our shareholders a notice instead of a paper copy of this proxy statement and our 2010 Annual Report. The notice contains instructions on how to access those documents over the Internet. The notice also contains instructions on how shareholders can receive a paper copy of our proxy materials, including this proxy statement, our 2010 Annual Report and a form of proxy card or voting instruction card. We believe that this process will conserve natural resources and reduce the costs of printing and distributing our proxy materials.

During the course of the meeting there will be the usual time for discussion of the items on the agenda and for questions regarding AEP' s affairs. Directors and officers will be available to talk individually with shareholders before and after the meeting.

Your vote is very important. Shareholders of record can vote in any one of the following three ways:

By internet, at www.envisionreports.com/AEP

By toll-free telephone at 800-652-8683

By completing and mailing your proxy card if you receive paper copies of the proxy materials

If your shares are held in the name of a bank, broker or other holder of record, you will receive instructions from the holder of record that you must follow in order for you to vote your shares.

If you have any questions about the meeting, please contact Investor Relations, American Electric Power Company, 1 Riverside Plaza, Columbus, Ohio 43215. The telephone number is 800-237-2667.

Sincerely,

/s/ Michael G. Morris

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NOTICE OF 2011 ANNUAL MEETING

American Electric Power Company, Inc.
1 Riverside Plaza
Columbus, Ohio 43215

TIME

9:30 a.m. Eastern Time on Tuesday, April 26, 2011

PLACE

Fawcett Center
The Ohio State University
2400 Olentangy River Road
Columbus, Ohio

ITEMS OF BUSINESS

(1) To elect 13 directors to hold office until the next annual meeting and until their successors are duly elected.

(2) To ratify the appointment of Deloitte & Touche LLP as independent registered public accounting firm for the year 2011.

(3) To hold an advisory vote on executive compensation.

(4) To hold an advisory vote on the frequency of holding an advisory vote on executive compensation.

(5) To consider and act on such other matters as may properly come before the meeting.

RECORD DATE

Only shareholders of record at the close of business on February 28, 2011, are entitled to notice of and to vote at the meeting or any adjournment thereof.

ANNUAL REPORT

Appendix A to this proxy statement has AEP' s audited financial statements, management' s discussion and analysis of results of operations and financial condition and the report of the independent registered public accounting firm.

PROXY VOTING

It is important that your shares be represented and voted at the meeting. Please vote in one of these ways:

(1) MARK, SIGN, DATE AND PROMPTLY RETURN your proxy card if you receive paper copies of the proxy materials.

(2) CALL TOLL-FREE by telephone at 800-652-8683.

(3) VISIT THE WEB SITE shown on the notice of internet availability of proxy materials to vote via the internet.

Any proxy may be revoked at any time before your shares are voted at the meeting.

March 14, 2011

D. Michael Miller
Secretary

Our annual meeting of shareholders also will be webcast at http://www.AEP.com/go/webcasts at 9:30 a.m. Eastern Time on April 26, 2011.

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Proxy Statement

March 14, 2011

Proxy and Voting Information

A notice of internet availability of proxy materials or paper copy of the proxy statement and form of proxy is to be mailed to shareholders on March 14, 2011, in connection with the solicitation of proxies by the Board of Directors of American Electric Power Company, Inc., 1 Riverside Plaza, Columbus, Ohio 43215, for the annual meeting of shareholders to be held on April 26, 2011 in Columbus, Ohio.

We use the terms “AEP,” the “Company,” “we,” “our” and “us” in this proxy statement to refer to American Electric Power Company, Inc. and, where applicable, its subsidiaries. All references to “years,” unless otherwise noted, refer to our fiscal year, which ends on December 31.

Who Can Vote. Only the holders of shares of AEP Common Stock at the close of business on the record date, February 28, 2011, are entitled to vote at the meeting. Each such holder has one vote for each share held on all matters to come before the meeting. On that date, there were 481,103,752 shares of AEP Common Stock, $6.50 par value, outstanding.

How You Can Vote. Shareholders of record can give proxies by (i) mailing their signed proxy cards; (ii) calling a toll-free telephone number; or (iii) using the internet. The telephone and internet voting procedures are designed to authenticate shareholders’ identities, to allow shareholders to give their voting instructions and to confirm that shareholders’ instructions have been properly recorded. Instructions for shareholders of record who wish to use the telephone or internet voting procedures are set forth on the proxy card.

When proxies are returned, the shares represented thereby will be voted by the persons named on the proxy card or by their substitutes in accordance with shareholders’ directions. If a proxy card is signed and returned without choices marked, it will be voted for the nominees for directors listed on the card and as recommended by the Board of Directors with respect to other matters. The proxies of shareholders who are participants in the Dividend Reinvestment and Stock Purchase Plan include both the shares registered in their names and the whole shares held in their Plan accounts on February 28, 2011.

Revocation of Proxies. A shareholder giving a proxy may revoke it at any time before it is voted at the meeting by giving notice of its revocation to the Company, by executing another proxy dated after the proxy to be revoked, or by attending the meeting and voting in person.

How Votes are Counted. The presence of the holders of a majority of the outstanding shares of common stock entitled to vote at the Annual Meeting, present in person or represented by proxy, is necessary to constitute a quorum. Abstentions and “broker non-votes” are counted as present and entitled to vote for purposes of determining a quorum. A “broker non-vote” occurs when a broker holding shares for a beneficial owner does not vote on a particular proposal because the broker does not have discretionary voting power for that particular item and has not received instructions from the beneficial owner.

Under New York Stock Exchange rules, the proposal to ratify the appointment of Deloitte & Touche as our independent registered public accounting firm is considered a “discretionary” item. This means that brokerage firms may vote in their discretion on this matter on behalf of their clients who have not furnished voting instructions. The proposals to elect directors, the advisory vote on executive compensation and the advisory vote on the frequency of holding the advisory vote on executive compensation are “non-discretionary” matters, which means that brokerage firms may not use their discretion to vote on such matters without express voting instructions from their customers.

At the 2009 annual meeting, we recommended and our shareholders approved amendments to our Articles of Incorporation to eliminate cumulative voting in election of directors which allowed the Company to amend its Bylaws to implement a majority voting standard for the election of directors in uncontested elections of directors. The election of directors at the Annual Meeting is an uncontested election, so for a nominee to be elected to the Board, the number of votes cast “for” the nominee’ s election must exceed the number of votes cast “against” his or her election. Abstentions and broker non-votes will not be considered votes cast “for” or “against” a nominee. If a nominee is not elected because he or she did not receive a greater number of votes “for” his or her election than “against” such election, he or she will be required to tender his or her resignation for the Board’ s consideration of whether to accept such resignation in accordance with our Bylaws.

Since the shareholders approved amendments to our Articles of Incorporation to eliminate cumulative voting in elections of directors, no shareholder has the right to cumulate his or her voting power in the election of directors at the Annual Meeting.

The votes cast “for” must exceed the votes cast “against” to approve the ratification of Deloitte & Touche LLP as our independent registered public accounting firm. Abstentions are not counted as votes “for” or “against” this proposal and therefore have no effect.

The votes cast “for” must exceed the votes cast “against” to approve the advisory vote regarding the compensation of the named executive officers as disclosed in the proxy statement. Abstentions and broker non-votes are not counted as votes “for” or “against” this proposal and therefore have no effect.

The advisory vote regarding the frequency of the shareholder vote to approve the compensation of the named executive officers will be determined by a plurality of the votes cast. Abstentions and broker non-votes are not counted as votes “for” or “against” this proposal and therefore have no effect.

Your Vote is Confidential. It is AEP’ s policy that shareholders be provided privacy in voting. All proxies, voting instructions and ballots, which identify shareholders, are held on a confidential basis, except as may be necessary to meet any applicable legal requirements. We direct proxies to an independent third-party tabulator, who receives, inspects, and tabulates them. Voted proxies and ballots are not seen by nor reported to AEP except (i) in aggregate number or to determine if (rather than how) a shareholder has voted; (ii) in cases where shareholders write comments on their proxy cards; or (iii) in a contested proxy solicitation.

Multiple Copies of Annual Report, Proxy Statement or Notice of Internet Availability of Proxy Materials to Shareholders. Securities and Exchange Commission (SEC) rules provide that more than one annual report, proxy statement or notice of internet availability of proxy materials need not be sent to the same address. This practice is commonly called “householding” and is intended to eliminate duplicate mailings of shareholder documents. Mailing of your annual report, proxy statement or notice of internet availability of proxy materials is being householded indefinitely unless you instruct us otherwise. We will deliver promptly upon written request a separate copy of the annual report, proxy statement or notice of internet availability of proxy materials to a shareholder at a shared address. To receive a separate copy of the annual report, proxy statement or notice of internet availability of proxy materials, write to AEP, attention: Investor Relations, at 1 Riverside Plaza, Columbus, OH 43215. If more than one annual report, proxy statement or notice of internet availability of proxy materials is being sent to your address, at your request, mailing of the duplicate copy can be discontinued by contacting our transfer agent, Computershare Trust Company, N.A. (Computershare), at 800-328-6955 or write to them at P.O Box 43078, Providence, RI 02940-3078. If you wish to resume receiving separate annual reports, proxy statements or notice of internet availability of proxy materials at the same address in the future, you may call Computershare at 800-328-6955 or write to them at P.O Box 43078, Providence, RI 02940-3078. The change will be effective 30 days after receipt.

Additional Information. Our website address is *www.aep.com*. We make available free of charge on the Investor Relations section of our website (*www.AEP.com/investors*) our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and all amendments to those reports as soon as reasonably practicable after such material is electronically filed with or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934 (Exchange Act). We also make available through our website other reports filed with or furnished to the SEC under the Exchange Act, including our proxy statements and reports filed by officers and directors under Section 16(a) of the Exchange Act. You may request any of these materials and information in print by contacting Investor Relations at: AEP, attention: Investor Relations, 1 Riverside Plaza, Columbus, OH 43215. We do not intend for information contained in our website to be part of this proxy statement. In addition, this proxy statement and the Annual Report on Form 10-K for the fiscal year ended December 31, 2010 are available at www.edocumentview.com/aep.

You also may read and copy any materials we file with the SEC at the SEC' s Public Reference Room at 100 F Street, N.E., Washington, DC, 20549. You may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site (*www.sec.gov*) that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC.

1. Election of Directors

Currently, AEP' s Board of Directors consists of 13 members. Messrs. E. R. Brooks and Donald M. Carlton will end their service as members of the Board effective as of the date of the annual meeting, but the Board is recommending the election of David J. Anderson and Richard C. Notebaert. Messrs. Anderson and Notebaert were recommended to the Board by a director search firm, which was paid a fee to identify and evaluate potential Board members. Mr. Hoaglin and Mr. Morris interviewed Messrs. Anderson and Notebaert and recommended them to the Committee on Directors and Corporate Governance. That Committee reviewed their qualifications and recommended them to the full board.

Thirteen directors are to be elected to hold office until the next annual meeting and until their successors have been elected. AEP' s Bylaws provide that the number of directors of AEP shall be such number, not less than 9 nor more than 17, as shall be determined from time to time by resolution of the Board.

The 13 nominees named on pages 4 to 6 were selected by the Board on the recommendation of the Committee on Directors and Corporate Governance of the Board, following individual evaluation of each incumbent nominee' s 2010 performance. The proxies named on the proxy card or their substitutes will vote for the Board' s nominees, unless instructed otherwise. All of the Board' s nominees were elected by the shareholders at the 2010 annual meeting, except for Messrs. Anderson and Notebaert. We do not expect any of the nominees will be unable to stand for election or be unable to serve if elected. If a vacancy in the slate of nominees should occur before the meeting, the proxies may be voted for another person nominated by the Board or the number of directors may be reduced accordingly.

Biographical Information. The following brief biographies of the nominees include their principal occupations, ages on the date of this statement, accounts of their business experience and names of certain companies of which they are directors. Data with respect to the number of shares of AEP' s Common Stock, options exercisable within 60 days and stock-based units beneficially owned by each of them appear on page 73.

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Nominees For Director

	**David J. Anderson** Morristown, New Jersey Age 61	Senior vice president and chief financial officer of Honeywell International, a diversified technology and manufacturing company, since 2003.
	**James F. Cordes** The Woodlands, Texas Age 70 Director since 2009	Retired executive vice president of The Coastal Corporation (1985-1997), a diversified energy company. Retired chairman and chief executive officer of ANR Pipeline Company (1985-1997), an interstate natural gas pipeline company. A director of Comerica, Inc. Mr. Cordes was formerly a director of Northeast Utilities (2001-2010).
	**Ralph D. Crosby, Jr.** McLean, Virginia Age 63 Director since 2006	Chairman of EADS North America, Inc., an aerospace company, since 2002. Retired Chief Executive Officer of EADS North America, Inc. (2002-2009). A director of Ducommun Incorporated.
	**Linda A. Goodspeed** Franklin, Tennessee Age 49 Director since 2005	Vice president of information systems of Nissan North America, Inc., an automobile manufacturer, since 2008. Managing partner of Wealthstrategies Financial Advisors, LLC since 2008. From 2001 to 2008, executive vice president and chief supply chain logistics and technology officer of Lennox International, Inc, a provider of climate control solutions. A director of Columbus McKinnon Corp.
	**Thomas E. Hoaglin** Columbus, Ohio Age 61 Director since 2008	Retired chairman and chief executive officer of Huntington Bancshares Incorporated, a bank holding company (2001-2009). A director of The Gorman-Rupp Company.
	**Lester A. Hudson, Jr.** Charlotte, North Carolina Age 71 Director since 1987	Professor and the Wayland H. Cato, Jr. Chair in Leadership at McColl School of Business at Queens University of Charlotte since 2003. Retired chairman, chief executive officer and president of Wunda Weve Carpets, Inc. and Dan River, Inc., each a textile manufacturer. A director of American National Bankshares Inc.

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Nominees For Director − continued

Michael G. Morris

Columbus, Ohio

Age 64

Director since 2004

Chairman and chief executive officer of AEP since 2004; and chairman and chief executive officer of all of its major subsidiaries since 2004. A director of certain subsidiaries of AEP with one or more classes of publicly held preferred stock or debt securities and other subsidiaries of AEP. A director of Alcoa Inc. and The Hartford Financial Services Group, Inc. Mr. Morris was formerly a director of Cincinnati Bell, Inc. (2005-2008).

Richard C. Notebaert

Chicago, Illinois

Age 64

Retired chief executive officer of Qwest Communications International Inc., a telecommunications systems company (2002-2007). A director of Aon Corporation and Cardinal Health, Inc. Mr. Notebaert was formerly a director of Qwest Communications International Inc. (2002-2007).

Lionel L. Nowell III

Cos Cob, Connecticut

Age 56

Director since 2004

Retired senior vice president and treasurer of PepsiCo, Inc., a food and beverage company (2001-2009). A director of Reynolds American Inc. Mr. Nowell was formerly a director of Church & Dwight, Inc. (2005-2007).

Richard L. Sandor

Chicago, Illinois

Age 69

Director since 2000

Founder and Former Chairman of Chicago Climate Exchange, Inc. (CCX), an environmental commodity trading exchange (2002-2010). Former chief executive officer of CCX (2002-2009). Former Chairman of the Chicago Climate Futures Exchange (CCFE), a derivative trading exchange (2004-2010). Former chief executive officer of CCFE (2004-2009). Former Chairman of Climate Exchange PLC, the parent of CCX and CCFE (2003-2010). Lecturer, University of Chicago Law School. Member of the International Advisory Council and Distinguished Professor of Environmental Finance of Guanghua School of Management at Peking University. Former member of the design committee of the Dow Jones Sustainability Index. Dr. Sandor was formerly a director of Intercontinental Exchange, Inc. (2005-2008) and Milennium Cell, Inc. (2005-2007).

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Nominees For Director − continued

	**Kathryn D. Sullivan** Columbus, Ohio Age 59 Director since 1997	Director, Battelle Center for Mathematics and Science Education Policy – The John Glenn School of Public Affairs at The Ohio State University since November 2006. Science Advisor to Columbus' science museum COSI (Center of Science & Industry) from December 2005 to November 2006. President and chief executive officer of COSI from 1996 to 2005. Former NASA space shuttle astronaut.
	**Sara Martinez Tucker** San Francisco, California Age 55 Director since 2009	Self-employed consultant since 2009. Retired Under Secretary of Education in the U.S. Department of Education (2006-2008). Chief executive officer and president of the Hispanic Scholarship Fund from 1997 to 2006.
	**John F. Turner** Moose, Wyoming Age 69 Director since 2008	Managing partner of Triangle X Ranch, a guest ranch in Jackson Hole, Wyoming, since 1960. Assistant Secretary of State of U.S. State Department' s Bureau of Oceans and International and Scientific Affairs from 2001 to 2005. Former director of the U.S. Fish and Wildlife Service from 1989 to 1993. A director of Ashland, Inc., International Paper Company and Peabody Energy Corporation.

AEP' s Board of Directors and Committees

Under New York law, AEP is managed under the direction of the Board of Directors. The Board establishes broad corporate policies and authorizes various types of transactions, but it is not involved in day-to-day operational details. During 2010, the Board held eight regular meetings, one of which was held in a city where we have a regional office and one of which was held in a city where we have facilities that the Board visited. We also had three special meetings. AEP encourages but does not require members of the Board to attend the annual shareholders' meeting. Last year, all directors attended the annual meeting.

Board Meetings and Committees. The Board expects that its members will rigorously prepare for, attend and participate in all Board and applicable committee meetings. Directors are also expected to become familiar with AEP' s management team and operations as a basis for discharging their oversight responsibilities.

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The Board has seven standing committees. The table below shows the number of meetings conducted in 2010 and the directors who currently serve on these committees. During 2010, no director attended fewer than 87% of the aggregate of the total number of meetings of the Board and the total number of meetings held by all committees during the period on which he or she served.

DIRECTOR	BOARD COMMITTEES						
	Audit	Directors and Corporate Governance	Policy	Executive	Finance	Human Resources	Nuclear Oversight
Mr. Brooks	X		X		X		
Dr. Carlton			X (Chair)			X	X
Mr. Cordes		X	X			X	
Mr. Crosby			X			X	X
Ms. Goodspeed	X		X				X
Mr. Hoaglin		X (Chair)	X	X		X	
Dr. Hudson		X	X	X		X (Chair)	
Mr. Morris			X	X (Chair)			
Mr. Nowell	X (Chair)	X	X	X	X		
Dr. Sandor			X	X	X (Chair)		
Dr. Sullivan			X		X		X (Chair)
Ms. Tucker	X	X	X				
Mr. Turner	X		X				X

2010 Meetings	9	6	3	0	4	7	5

The functions of the committees are described below.

The ***Committee on Directors and Corporate Governance*** has the responsibilities set forth in its charter, including:

1. Recommending the size of the Board within the limits imposed by the Bylaws.
2. Recommending selection criteria for nominees for election or appointment to the Board.
3. Conducting independent searches for qualified nominees and screening the qualifications of candidates recommended by others.
4. Recommending to the Board nominees for appointment to fill vacancies on the Board as they occur and the slate of nominees for election at the annual meeting.
5. Reviewing and making recommendations to the Board with respect to compensation of directors and corporate governance.
6. Recommending members to serve on committees and chairs of the committees of the Board.
7. Reviewing the independence and possible conflicts of interest of directors and executive officers.
8. Overseeing the AEP Corporate Compliance Program.
9. Overseeing the annual evaluation of the Board of Directors.
10. Reviewing annually the performance of individual directors.
11. Overseeing the implementation of AEP' s Related Person Transaction Approval Policy.
12. Overseeing AEP' s Sustainability Report, including the material about political contributions.

13. Overseeing elements of the Company' s risks that are within the scope of the Committee' s responsibility as assigned to it by the Board of Directors.

A copy of the charter can be found on our website at *www.AEP.com/investors/corporategovernance*. Consistent with the rules of the NYSE and the SEC and our Director Independence Standards, all members of the Committee on Directors and Corporate Governance are independent.

The ***Human Resources Committee*** (the HR Committee) annually reviews and approves AEP' s executive compensation in the context of the performance of management and the Company. None of the members of the HR Committee is or has been an officer or employee of any AEP System company. In addition, each of the current members of the HR Committee has been determined to be independent by the Board in accordance with SEC and New York Stock Exchange (NYSE) rules and our Director Independence Standards. In addition, each member is a "non-employee director" as defined in Rule 16b-3 under the Exchange Act and is an "outside director" as defined in Section 162(m) of the Internal Revenue Code.

The HR Committee also reviews the Compensation, Discussion and Analysis section of this proxy statement and recommends that it be included in the Company' s Annual Report on Form 10-K.

The HR Committee has the responsibilities set forth in its charter, a copy of which can be found on our website at *www.AEP.com/investors/corporategovernance.*

For a more complete description of the HR Committee' s responsibilities, see the Human Resources Committee Report on page 44.

The ***Audit Committee*** is responsible for, among other things, the appointment of the independent registered public accounting firm (independent auditor) for the Company; reviewing with the independent auditor the plan and scope of the audit and approving audit fees; monitoring the adequacy of financial reporting and internal control over financial reporting and meeting periodically with the internal auditor and the independent auditor. A more detailed discussion of the purposes, duties and responsibilities of the Audit Committee is found in the Audit Committee charter, a copy of which can be found on our website at *www.AEP.com/investors/corporate governance*. Consistent with the rules of the NYSE and the SEC and our Director Independence Standards, all members of the Audit Committee are independent. The Board has determined that Mr. Nowell is an audit committee financial expert as defined by the SEC.

The ***Finance Committee*** monitors and reports to the Board with respect to the capital requirements and financing plans and programs of AEP and its subsidiaries, including reviewing and making recommendations concerning the short and long-term financing plans and programs of AEP and its subsidiaries. The Finance Committee also provides recommendations to the Board on dividend policy, including the declaration and payment of dividends. The Finance Committee also reviews and approves the treasury policies of the Company.

The ***Nuclear Oversight Committee*** is responsible for overseeing and reporting to the Board with respect to the management and operation of AEP' s nuclear generation.

The ***Policy Committee*** is responsible for examining AEP' s policies on major public issues affecting the AEP System, including environmental, technology, fuel supply, industry change and other matters.

The ***Executive Committee*** is empowered to exercise all the authority of the Board, subject to certain limitations prescribed in the Bylaws, during the intervals between meetings of the Board.

The Board' s role in AEP' s risk oversight process

The Board has the overall responsibility for overseeing the Company' s management of risks. Management is responsible for identifying and managing the Company' s risks. The Board reviews the Company' s processes for identifying and managing risks and communicating with the Board about those risks to help ensure that the processes are effective.

Like other companies, we have very diverse risks. These include financial and accounting risks, capital deployment risks, operational risks, compensation risks, liquidity risks, litigation risks, strategic risks, regulatory risks, reputation risks, natural-disaster risks and technology risks. Some critical risks having enterprise-wide significance, such as corporate strategy and capital budget, require the full Board' s active oversight, but our Board committees also play a key role because they can devote more time to reviewing specific risks. For example, our Nuclear Oversight Committee focuses on the specific risks of operating a nuclear plant. The Board is also responsible, therefore, for ensuring that these types of risks are properly delegated to the appropriate committee, and that the risk oversight activities are properly coordinated and communicated among the Board and the various committees that oversee the risks.

Our other committees oversee both specific and broad types of risks. Some of the committees have oversight responsibility for specific risks that are inherent in carrying out their responsibilities set forth in their charters. For example, the Audit Committee is responsible for overseeing financial reporting risks. Management prepared and categorized a list of the Company' s major types of risks. The Audit Committee and the Directors and Corporate Governance Committee reviewed that list and proposed an assignment of risks either to the full Board or to specific committees. The Board reviewed the recommendations and adopted the proposed allocation of responsibilities.

Under the NYSE' s listing standards, our Audit Committee must discuss AEP' s policies for risk assessment and risk management. The Audit Committee oversees the process of identifying major enterprise risks and communicates those risks to the Board for assignment of oversight among the Board and the various committees. Our Chief Risk Officer, Chief Accounting Officer and General Counsel attend all Audit Committee meetings. The Audit Committee oversees the Company' s maintenance of financial and disclosure controls and procedures and also specifically reviews our litigation and regulatory risks as part of their review of the Company' s disclosures.

Our Finance Committee broadly oversees our financial risks, which include energy trading risks, liquidity risks and interest rate risks. For example, the Finance Committee reviews and approves the Company' s risk policies relating to our power marketing and hedging activities and also oversees the performance of the assets in our pension plans. Our Chief Risk Officer and General Counsel attend all Finance Committee meetings.

Our HR Committee reviews the Company' s incentive compensation practices to ensure they do not encourage excessive risk-taking and are consistent with the Company' s risk tolerance. The HR Committee also oversees our succession planning and executive leadership development. Our senior human resources officers attend all of the HR Committee meetings.

The Directors and Corporate Governance Committee focuses on corporate governance risks and oversees the Company' s Corporate Compliance Program, which includes the Company' s whistleblower program. Our General Counsel attends all Directors and Corporate Governance Committee meetings.

Compensation Risk

As specified in its charter, the HR Committee (with the assistance of its independent compensation consultant and Company management) reviewed the Company' s compensation policies and practices for all employees, including executive officers, and determined that the compensation programs are not reasonably likely to have a material adverse effect on the Company.

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The Company has designed its executive compensation process, with oversight from the HR Committee, to identify and manage risk and to ensure it does not encourage excessive risk taking. The base salary component, which represents approximately 16% of our CEO’ s total compensation opportunity, discourages risk-taking because its value and payment is contingent only upon the CEO’ s continued employment with the Company. The Company also provides annual and long-term incentive compensation in amounts that represent approximately 18% and 67% of our CEO’ s total compensation opportunity, respectively. The HR Committee believes this appropriately allocates our compensation among base salary and short and long-term incentive compensation opportunities in such a way as to not encourage excessive risk-taking. The Company’ s incentive compensation also has the following characteristics:

Incentive award opportunities for all employees are capped generally at 200% of their target. Capping the potential payout limits the extent that employees could potentially profit by taking on excessive risk,

The HR Committee provides the large majority of incentive compensation to executive officers as long-term stock-based incentive compensation to ensure that short-term performance is not encouraged or rewarded at the expense of long-term performance. This is important because of the large amount of long-term investments required in our business,

Annual incentive compensation for all employees, including executive officers, is based on AEP’ s ongoing earnings per share less a potential fatality deduction, which is a deduction that would apply to executive officers if AEP experienced a fatal work related employee accident. This insures that no employees are encouraged to achieve earnings objectives at the expense of workplace safety,

The primary metrics used in the Company’ s incentive plans are earnings per share and total shareholder return, which are both robust measures of shareholder value that reduce the risk that employees might be encouraged to pursue other objectives that increase risk or reduce financial performance,

Annual and long-term incentive compensation programs are reviewed by AEP’ s internal audit staff,

All incentive award payouts to senior officers are subject to the review and approval of the HR Committee, or in the case of Mr. Morris, the independent members of the Board, and they retain the discretion to reduce any payouts,

Both annual and long-term incentive awards are subject to the Company’ s policy that makes incentive payments and deferred compensation subject to recoupment as described in Compensation Discussion and Analysis on page 40,

AEP has primarily granted long-term incentive awards in the form of performance units with a three-year performance and vesting period, which aligns the interests of employees to the long-term interests of shareholder and helps retain management, Executives (currently 46) are subject to our executive stock ownership requirements as described in Compensation Discussion and Analysis on page 38,

We have not issued stock options to our executive officers since 2003, as stock options may provide an incentive to take excessive risks to increase the Company’ s stock price, and

It is part of a market competitive compensation package that enables the Company to attract, retain and motivate executives with the skills and experience needed to manage a company of AEP’ s considerable size and complexity in a highly regulated electric utility industry. This reduces risk by better ensuring both strong management competence and continuity.

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Corporate Governance

AEP maintains a corporate governance page on its website that includes key information about corporate governance initiatives, including AEP' s Principles of Corporate Governance, AEP' s Principles of Business Conduct, Code of Business Conduct and Ethics for members of the Board, Director Independence Standards, and charters for the Audit, Directors and Corporate Governance and Human Resources Committees of the Board. The corporate governance page can be found at *www.aep.com/investors/corporategovernance*. Printed copies of all of these materials also are available upon written request to Investor Relations at: AEP, attention: Investor Relations, 1 Riverside Plaza, Columbus, Ohio 43215.

AEP' s policies and practices reflect corporate governance initiatives that are designed to comply with SEC rules, the listing requirements of the New York Stock Exchange (NYSE) and the corporate governance requirements of the Sarbanes-Oxley Act of 2002, including:

- The Board of Directors has adopted corporate governance policies;
- All but one of its Board members (the CEO) is independent of AEP and its management;
- All members of the Audit Committee, Human Resources Committee and the Committee on Directors and Corporate Governance are independent;
- The members of the Board meet regularly without the presence of management, and the independent members of the Board meet at least once a year;
- AEP has a code of business conduct that also applies to its principal executive officer, principal financial officer and principal accounting officer and will promptly disclose waivers of the code for these officers;
- The charters of the Board committees clearly establish their respective roles and responsibilities;
- The Board, the Committee on Directors and Corporate Governance, the Audit Committee and the HR Committee conduct annual self-assessments. The Committee on Directors and Corporate Governance also evaluates annually the performance of the individual directors.

Directors

The Committee on Directors and Corporate Governance is responsible for recruiting new directors and uses a variety of methods for identifying and evaluating nominees for director. The Committee on Directors and Corporate Governance regularly assesses the appropriate size and composition of the Board, the needs of the Board and the respective committees of the Board and the qualifications of candidates in light of these needs. Candidates may come to the attention of the Committee on Directors and Corporate Governance through shareholders, management, current members of the Board or search firms. Shareholders who wish to recommend candidates to the Committee on Directors and Corporate Governance may do so by following the procedures described in Shareholder Proposals and Nominations on page 74.

Director qualifications

The Company' s Principles of Corporate Governance are available on its website at www.aep.com/investors/corporategovernance/docs/principles.pdf. With respect to director qualifications and attributes, the Principles require the following:

> In nominating a slate of Directors, the Board' s objective, with the assistance of the Committee on Directors and Corporate Governance, is to select individuals with skills and experience that can be of assistance to management in operating the Company' s business.
>
> Directors should possess the highest personal and professional ethics, integrity and values, and be committed to representing the long-term interests of the shareholders. They must also have an inquisitive and objective perspective, practical wisdom and mature judgment.

These requirements are expanded in the Criteria for Evaluating Directors, which was initially adopted by the Committee on Directors and Corporate Governance in 2005 and subsequently reviewed and refined several times, most recently at the Committee’ s meeting in December 2009. The Criteria are available on the Company’ s website at www.aep.com/investors/corporategovernance/docs/criteriaforevaluatingdirectors.pdf.

As indicated in the Principles and the Criteria, directors should have personal attributes such as high integrity, intelligence, wisdom and judgment. In addition, they should have skills and experience that mesh effectively with the skills and experience of other Board members, so that the talents of all members blend together to be as effective as possible in overseeing a large electric utility business.

Mr. Morris is the Chairman and Chief Executive Officer of the Company. He has undergraduate and graduate degrees in biology and a law degree. Mr. Morris has worked for nearly four decades in the utility industry, originally in a consulting firm and then in progressively more responsible positions in gas and electric utility companies. Mr. Morris is in his 14th year as chairman and chief executive officer of a large, multi-state electric utility company, having led Northeast Utilities from 1997 – 2003 and the Company since January 2004.

Dr. Hudson is the Company’ s Presiding Director and Chair of the Human Resources Committee. In addition to having a doctorate in business strategy, Dr. Hudson teaches management and strategy to graduate students, and previously he was the chief executive of two public companies.

Mr. Nowell chairs the Audit Committee and is designated as the Audit Committee Financial Expert, a position required by the rules of the New York Stock Exchange and the SEC. Mr. Nowell is a Certified Public Accountant and served until his retirement in 2009 in senior financial positions with Pepsico, RJR Nabisco, Pillsbury and other major companies in the food and beverage industry.

Two directors (Mr. Cordes – natural gas and Ms. Tucker – telecommunications) and one nominee (Mr. Notebaert – telecommunications) spent major parts of their careers in regulated utility companies that have many similarities to our business. And, two directors (Messrs. Cordes and Turner) understand our industry from past service on the boards of directors of another electric utility.

Our business is highly regulated, and several directors (Messrs. Cordes, Hoaglin and Morris and Ms. Tucker) and one nominee (Mr. Notebaert) spent careers in industries that are also highly regulated. Mr. Notebaert spent more than 11 years as Chairman and Chief Executive Officer of publicly-traded companies Qwest Communications International and Ameritech Corporation. Ms. Tucker spent a large part of her career at AT&T in senior management positions in human resources and customer service operations. Mr. Cordes spent many years as an executive in the natural gas business. Two directors (Mr. Turner and Ms. Tucker) have spent time as senior governmental officials and appreciate the issues of regulation from that perspective. Mr. Turner also served in the Wyoming state legislature for many years. Our business is also very capital intensive and involves sophisticated heavy equipment and facilities; Mr. Crosby’ s experience in the aerospace industry gives him a background in a comparably capital intensive and sophisticated industry.

Science, engineering and technology are important in our business. Many of the Company’ s directors have undergraduate and/or graduate degrees in engineering (Messrs. Cordes and Crosby and Ms. Goodspeed), while others have undergraduate and/or graduate degrees in scientific subjects (Messrs. Morris and Turner and Dr. Sullivan). Dr. Sullivan is a former NASA astronaut and former Chief Scientist, National Oceanic & Atmospheric Administration. Dr. Sullivan also was the former head of a science museum in Columbus, Ohio, the Company' s headquarters city. Ms. Goodspeed is an engineering graduate with an M.B.A, who has worked in responsible positions in automotive and heating/cooling manufacturing. She is currently the chief information officer of an automobile manufacturer.

Environmental compliance is essential for success in our industry. Mr. Turner was chief executive of a national environmental organization and headed a governmental agency with environmental responsibilities, and Dr. Sandor headed a financial exchange focused on environmental financial products.

Several directors in addition to Mr. Nowell have significant experience in finance, auditing or other financial or accounting roles. Mr. Hoaglin was the chief executive of a regional bank headquartered in Columbus with a footprint that significantly overlaps the midwestern part of the Company' s service territory. Dr. Sandor was chief economist at a commodities exchange before he created the Chicago Climate Exchange (CCX) and he taught finance at the graduate level. Director nominee, Mr. Anderson, is currently the Chief Financial Officer of Honeywell International, and has served as Chief Financial Officer with ITT Industries and RJR Nabisco and other major companies.

And, the experience gained from leading large, complex organizations brings invaluable perspective to a Board. Messrs. Hoaglin, Hudson and Notebaert have been chief executive officers of public companies and Mr. Morris currently serves as a chief executive. Messrs. Cordes and Crosby have been chief executives of major subsidiaries of public companies, while Dr. Sullivan and Ms. Tucker have headed substantial non-profit organizations. Messrs. Cordes, Crosby, Hoaglin, Hudson, Morris, Notebaert, Nowell, Sandor and Turner, Ms. Goodspeed and Dr. Sullivan bring to the board experience gained from currently or previously serving on the boards of directors of other public companies.

Any summary of the specific skills and attributes of individual directors is necessarily very high level. It cannot cover the full range of the skills, experience and personal attributes that each contributes to service on the Board of Directors, nor can it explain the ways in which the abilities and perspectives of different directors interact to benefit the Company.

Board Diversity

Our Criteria for Evaluating Directors also includes the Company' s statement regarding how the Board considers diversity in identifying nominees for our Board. The Criteria provide:

> Two central objectives in selecting board members and continued board service are that the skills, experiences and perspectives of the Board as a whole should be broad and diverse, and that the talents of all members of the Board should blend together to be as effective as possible. In particular, the Board should be balanced by having complementary knowledge, expertise and skill in areas such as business, finance, accounting, marketing, public policy, manufacturing and operations, government, technology, environmental and other areas that the Board has decided are desirable and helpful to fulfilling its role. Diversity in gender, race, age, tenure of board service, geography and background of directors, consistent with the Board' s requirements for knowledge and experience, are desirable in the mix of the Board.

Our Directors and Corporate Governance Committee considers these criteria each year as it determines the slate of directors to recommend to the Board for election at our annual meeting. It also considers these criteria each time a new director is recommended for election to the Board. The Board believes that its implementation of this policy is effective in considering the diversity of the members of the Board.

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Director Independence

In accordance with NYSE standards, a majority of the members of the Board of Directors must qualify as independent directors. No member of the Board is independent unless the Board affirmatively determines annually that such member is independent. The Board has adopted categorical standards to assist it in making this determination of director independence (Director Independence Standards). These standards can be found on our web site at www.AEP.com/investors/corporategovernance.

Each year, our directors complete a questionnaire that elicits information to assist the Committee on Directors and Corporate Governance in assessing whether the director meets the Company' s independence standards. Each director lists all the companies and charitable organizations that he or she, or an immediate family member, has a relationship with as a partner, trustee, director or officer, and indicates whether that entity made or received payments from AEP. The Company reviews its financial records to determine the amounts paid to or received from those entities. A list of the entities and the amounts AEP paid to or received from those entities is provided to the Committee on Directors and Corporate Governance. Utilizing this information, the Committee on Directors and Corporate Governance evaluates, with regard to each director, whether the director has any material relationship with AEP or any of its subsidiaries. The Committee on Directors and Corporate Governance determines whether the amount of any payments between those entities and AEP could interfere with a director' s ability to exercise independent judgment. The Committee on Directors and Corporate Governance also discusses any other relevant facts and circumstances regarding the nature of these relationships, to determine whether other factors, regardless of the categorical standards the Board has adopted, might impede a director' s independence.

We are a large electric utility company that operates in parts of eleven different states. Any organization that does business in our service territory buys electricity from one of our subsidiaries. Many of our directors live in our service territory or are executives, directors or trustees of organizations that do business in our service area. However, all of those organizations purchase electricity from us at rates set by a regulatory commission. There are no unique negotiated rates with any of those organizations. Therefore, the Committee on Directors and Corporate Governance determined that none of those relationships impedes a director' s independence.

We make numerous charitable contributions to nonprofit and community organizations and universities in the states where we do business. Again, because many of our directors live in our service territory and are highly accomplished individuals in their communities, our directors are frequently affiliated with many of the same educational institutions, museums, charities and other community organizations. None of our directors, however, is an executive officer of those nonprofit organizations. Nonetheless, the Committee on Directors and Corporate Governance reviews all charitable contributions made by AEP to organizations with which our directors or their immediate family members are affiliated. The Committee on Directors and Corporate Governance also reviewed contributions made from The American Electric Power Foundation, which was created to support and play an active, positive role in the communities in which AEP operates by contributing funds to organizations in those communities. The Committee on Directors and Corporate Governance determined that the Company' s contributions were not materially influenced by the director' s relationship with the organization, and therefore none of these relationships conflict with the interests of the Company or would impair the director' s independence or judgment.

The Board' s independence determinations specifically included reviewing the following transactions:

Ms. Goodspeed is an executive officer of a company with which the Company does business. Ms. Goodspeed is an executive at Nissan North America, Inc. As explained earlier, although Nissan purchases electricity from our subsidiaries, the Board does not believe that those transactions impair the independence of Ms. Goodspeed.

Mr. Anderson is also an executive officer of a company (Honeywell International) with which the Company does business. As explained earlier, although Honeywell purchases electricity from our subsidiaries, and the Company purchased an insignificant amount of goods from Honeywell, the Board does not believe that those transactions impair the independence of Mr. Anderson.

Dr. Sandor served as Chairman of CCX and Chicago Climate Futures Exchange (CCFE) until he stepped down from those positions when those companies were sold in June 2010. Although AEP and its subsidiaries transacted trades of greenhouse gas emission allowances on the CCX during 2010, AEP paid less than $71,000 to CCX and CCFE in 2010. Because Dr. Sandor is no longer associated with CCX and CCFE and AEP' s payments during 2010 were insignificant, the Board has determined that Dr. Sandor meets the independence standards and that he is an independent director.

Mr. Turner is a director of Peabody Energy Corporation, another company that transacted business with AEP. However, Mr. Turner is not an employee or executive officer of that company. Mr. Turner was chief executive of a national environmental organization and headed a governmental agency with environmental responsibilities, so Mr. Turner serves on boards of companies where environmental compliance is essential for success. Although we purchase a significant amount of coal from Peabody Energy Corporation, we entered into these coal buying relationships with Peabody in the ordinary course of business before Mr. Turner joined our Board. The nature of our coal purchased from Peabody since Mr. Turner became an AEP director is consistent with the nature before he was elected. In addition, since Mr. Turner became an AEP director, any AEP purchases from Peabody were awarded through a competitive process.

As a result of this review, the Board has determined that, other than Mr. Morris, each of the director nominees standing for election, including Messrs. Anderson, Cordes, Crosby, Hoaglin, Hudson, Notebaert, Nowell and Turner, Dr. Sandor, Ms. Goodspeed, Dr. Sullivan and Ms. Tucker, has no material relationship with the Company (either directly or as a partner, stockholder or officer of an organization that has a relationship with the Company) and is independent within the meaning of the Company' s Director Independence Standards.

Involvement by Mr. Hoaglin in Certain Legal Proceedings

On June 2, 2005, Huntington Bancshares Incorporated (Huntington) announced that the SEC approved a settlement of its previously announced formal investigation into certain financial accounting matters relating to fiscal years 2002 and earlier and certain related disclosure matters. As a part of the settlement, the SEC instituted a cease and desist administrative proceeding and entered a cease and desist order and also filed a civil action in federal district court pursuant to which, without admitting or denying the allegations in the complaint, Huntington and Mr. Hoaglin consented to pay civil money penalties. Without admitting or denying the charges in the administrative proceeding, Mr. Hoaglin agreed to cease and desist from committing and/or causing the violations charged as well as any future violations of these provisions. Additionally, Mr. Hoaglin agreed to pay disgorgement, pre-judgment interest and penalties in the amount of $667,609.

Shareholder Nominees for Directors

The Committee on Directors and Corporate Governance will consider shareholder recommendations of candidates to be nominated as directors of the Company. All such recommendations must be in writing and submitted in accordance with the procedures described under Shareholder Proposals and Nominations on page 74 and must include information required in AEP' s Policy on Consideration of Candidates for Director Recommended by Shareholders. A copy of this policy is on our website at www.AEP.com/investors/corporategovernance. Shareholders' nominees who comply with these procedures will receive the same consideration that all other nominees receive.

Board Leadership

Mr. Morris is in his 14th year leading large, multi-state, publicly held electric utility companies. He has been the Company' s Chairman and Chief Executive Officer since early 2004. Before that, he had held the same positions at another publicly held electric utility company from August 1997 to the end of 2003. Mr. Morris has extensive knowledge about and influence within the electric utility industry, as indicated from his current and past leadership positions with the Institute of Nuclear Power Operations, the Edison Electric Institute and the Business Roundtable, among other organizations. In addition to serving on the Company' s Board, Mr. Morris sits on the boards of directors of two other large public companies, and he has been a panelist at prominent corporate governance conferences.

Because of Mr. Morris' longstanding experience with the Company and other industry participants and the quality of his performance in these roles, and his extensive experience as a corporate director, the Board believes that the Company' s best interests are currently best served by Mr. Morris being both chairman and chief executive officer.

Dr. Hudson has been the Presiding Director of the Board since 2003. The purpose of the Presiding Director is to promote the independence of the Board in order to represent the interests of the shareholders. The Presiding Director is selected by non-management directors.

The Presiding Director is responsible for working closely with the chief executive officer to finalize information flow to the Board, set meeting agendas and arrange meeting schedules. He also chairs meetings of the non-management directors and serves as principal liaison between the non-management directors and management. In addition, Dr. Hudson has the ability to call special meetings of the Board, as needed. He has the authority to retain outside legal counsel or other advisors as needed by the Board. He provides a channel of communications between the directors and management, assures that directors receive timely and necessary information in advance of meetings, and receives communications from shareholders on behalf of non-management directors.

The Board believes that the allocation of responsibilities between Mr. Morris and Dr. Hudson works well, so that, with these individuals in place, it is not necessary to have a separate board chair and chief executive. Mr. Morris intends to retire as chief executive officer in late 2011, when he becomes 65 years old. Whether his successor as chief executive officer will also hold the office of chairman of the Board of Directors will be determined at the time in light of the successor' s skills and experience and other relevant considerations.

Communicating with the Board

Anyone who would like to communicate directly with our Board, our non-management directors as a group or Dr. Hudson, our Presiding Director, may submit a written communication to American Electric Power Company, Inc., P.O. Box 163609, Attention: AEP Non-Management Directors, Columbus, Ohio 43216. AEP' s Business Ethics and Corporate Compliance department will review such inquiries or communications. Communications other than advertising or promotions of a product or service will be forwarded to our Board, our non-management directors as a group or our Presiding Director, as applicable.

Transactions with Related Persons

The American Electric Power Company, Inc. Related Person Transaction Approval Policy (Policy) was adopted by the Board in December 2006. The written Policy is administered by the Committee on Directors and Corporate Governance. A copy of the Policy is available on our website at www.AEP.com/investors/corporategovernance.

The Policy defines a "Transaction with a Related Person" as any transaction or series of transactions in which (i) the Company or a subsidiary is a participant, (ii) the aggregate amount involved exceeds $120,000 and (iii) any "Related Person" has a direct or indirect material interest. A "Related Person" is any Director or member of the executive council or Section 16 officer of the Company, any nominee for director, any shareholder owning in excess of 5% of the total equity of the Company and any immediate family member of any such person.

The Directors and Corporate Governance Committee considers all of the relevant facts and circumstances in determining whether or not to approve such transaction and approves only those transactions that are in the best interests of the Company. The Directors and Corporate Governance Committee considers various factors, including, among other things: the nature of the related person' s interest in the transaction; whether the transaction involves arms-length bids or market prices and terms; the materiality of the transaction to each party; the availability of the product or services through other sources; whether the transaction would impair the judgment of a director or executive officer to act in the best interest of the Company; the acceptability of the transaction to the Company' s regulators; and in the case of a non-employee director, whether the transaction would impair his or her independence or status as an "outside" or "non-employee" director.

If Company management determines it is impractical or undesirable to wait until a meeting of the Directors and Corporate Governance Committee to consummate a Transaction with a Related Person, the Chair of the Corporate Governance Committee may review and approve the Transaction with a Related Person. Any such approval is reported to the Directors and Corporate Governance Committee at or before its next regularly scheduled meeting.

No approval or ratification of a Transaction with a Related Person necessarily satisfies or supersedes the requirements of the Company' s Code of Business Conduct and Ethics for Members of the Board of Directors or AEP' s Principles of Business Conduct applicable to any Related Person. To the extent applicable, any Transaction with a Related Person is also considered in light of the requirements set forth in those documents.

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DIRECTOR COMPENSATION

Directors who are employees of the Company receive no additional compensation for service as a director other than accidental insurance coverage. The following table presents the compensation provided by the Company in 2010 to the non-employee directors.

Name	Fees Earned Or Paid in Cash ($) (1)	Stock Awards ($) (2)(3)	All Other Compensation ($) (4)(5)(6)	Total ($)
E. R. Brooks	94,750	123,000	3,241	220,991
Donald M Carlton	84,500	123,000	3,241	210,741
James F. Cordes	84,500	123,000	2,741	210,241
Ralph D. Crosby, Jr.	84,500	123,000	741	208,241
Linda A. Goodspeed	94,750	123,000	741	218,491
Thomas E. Hoaglin	94,500	123,000	741	218,241
Lester A. Hudson, Jr.	127,000	123,000	7,741	257,741
Lionel L. Nowell III	121,000	123,000	741	244,741
Richard L. Sandor	82,000	123,000	741	205,741
Kathryn D. Sullivan	82,000	123,000	741	205,741
Sara M. Tucker	90,750	123,000	5,241	218,991
John F. Turner	94,750	123,000	741	218,491

(1) Consists of amounts described below under Director Compensation and Stock Ownership – Annual Retainers and Fees. For Mr. Nowell compensation includes $16,250 paid for services as Chairman of the Audit Committee. With respect to Mr. Brooks, Mr. Nowell,

Mr. Turner and Ms. Goodspeed compensation includes $12,750 paid for services as members of the Audit Committee for the full year, and for Ms. Tucker compensation includes $8,750 paid for services as a member of the Audit Committee for part of the year. For Dr. Hudson, Dr. Carlton, Mr. Cordes, Mr. Crosby and Mr. Hoaglin compensation includes $2,500 paid for services as members of the Human Resources Committee. For Dr. Hudson, compensation includes $11,250 paid for services as chairman of the HR Committee and $21,250 paid for services as Presiding Director. For Dr. Hudson, Mr. Hoaglin and Mr. Nowell, compensation includes $10,000 for services on an ad hoc CEO Search Committee.

(2) Consists of awards under the Stock Unit Accumulation Plan for Non-Employee Directors in 2010 described below under Director Compensation and Stock Ownership – Stock Unit Accumulation Plan. AEP Stock Units are credited to directors quarterly, based on the closing price of AEP common stock on the payment date. The grant date fair value of these awards for a full year of service was $123,000.

(3) Each non-employee director received 3,552 AEP stock units in 2010. See Share Ownership of Directors and Executive Officers on page 73 for the aggregate number of stock awards outstanding for each director as of February 22, 2011.

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(4) Consists of premiums for accidental death insurance and annual costs of the Central and South West Corporation Memorial Gift Program and matching gift contributions. The following table presents the components of All Other Compensation for each non-employee director:

Name	Premiums ($)	Memorial Gifts ($)	Matching Gifts ($)(6)
E. R. Brooks	741	Note 5	2,500
Donald M Carlton	741	Note 5	2,500
James F. Cordes	741	-0-	2,000
Ralph D. Crosby, Jr.	741	-0-	-0-
Linda A. Goodspeed	741	-0-	-0-
Thomas E. Hoaglin	741	-0-	-0-
Lester A. Hudson, Jr.	741	-0-	7,000
Lionel L. Nowell III	741	-0-	-0-
Richard L. Sandor	741	Note 5	-0-
Kathryn D. Sullivan	741	-0-	-0-
Sara M. Tucker	741	-0-	4,500
John F. Turner	741	-0-	-0-

(5) AEP is continuing a memorial gift program for former Central and South West Corporation (CSW) directors and executive officers who had been previously participating in this program. The program currently has 24 participants, including the three former CSW directors listed above. Under this program, AEP makes donations in a director’ s name to up to three charitable organizations in an aggregate amount of up to $500,000, payable by AEP upon such person’ s death. AEP maintains corporate-owned life insurance policies to support portions of the program. AEP paid an annual premium of $67,659 on those policies for 2010. In addition, the Company made donations in the amount of $500,000 upon the death of one of the program’ s participants.

(6) Directors may participate in our Matching Gifts Program on the same terms as AEP employees. Under the program, AEP will match up to $2,500 per institution each year in charitable contributions from a director.

Directors Compensation and Stock Ownership

Annual Retainers and Fees. The Board has determined that Board compensation should consist of a mix of cash and AEP stock units. In September 2010, upon the recommendation of the Committee on Directors and Corporate Governance and taking into account comparative data from Meridian Compensation Partners, LLC, the Board determined that effective October 1, 2010 (i) the amount of AEP stock units awarded to non-employee directors pursuant to the Stock Unit Accumulation Plan should increase from $120,000 annually to $132,000 annually, (ii) the amount of the annual cash retainer paid to non-employee directors should increase from $80,000 annually to $88,000 annually, (iii) the Presiding Director annual fee should increase from $20,000 to $25,000, (iv) the annual fee for the Chairman of the Audit Committee should increase from $15,000 to $20,000, (v) the annual fee for the Chairman of the HR Committee should increase from $10,000 to $15,000, (vi) the annual fee for members of the Audit Committee should increase from $12,000 to $15,000, and (vii) the annual fee for members of the HR Committee should be $10,000. Each of these cash retainers is paid in quarterly increments.

The Company believes that the standard director compensation amount compensates directors appropriately for all general services that are rendered as a director, committee member, committee chair or as Presiding Director, including education and training appropriate to the director' s responsibilities. The Company believes, however, that special compensation can be appropriate when individual directors are asked to undertake special assignments requiring a significant amount of additional time, effort and responsibility. The Board' s Special Compensation Policy provides for directors to be compensated at a daily rate when called upon to undertake special additional services beyond those contemplated by the Annual Retainer. Under the Special Compensation Policy, the Committee on Directors and Corporate Governance determines (a) the amount of any special compensation in light of the actual or anticipated time, effort and responsibility required of the director and (b) the form of special compensation, which may include a per diem fee, an hourly fee, a flat fee or any other reasonable payment or payments. Special compensation in the amount of $10,000 was paid to Dr. Hudson, Mr. Hoaglin and Mr. Nowell for their service on an ad hoc CEO Search Committee of the Board of Directors.

Expenses. Non-employee directors are reimbursed for expenses incurred in attending Board, committee and shareholder meetings. Directors are also reimbursed for reasonable expenses associated with other business activities that benefit the Company, including participation in director education programs.

Spouses may occasionally join non-employee directors on Company aircraft when a non-employee director is traveling to or from Board meetings or other business activities. The Company generally provides for, or reimburses the expenses of, the non-employee directors and their spouses for attendance at such meetings. The Board has eliminated tax gross-ups on all director perquisites.

Retainer Deferral Plan. The Retainer Deferral Plan for Non-Employee Directors is a non-qualified deferred compensation plan that permits non-employee directors to choose to defer up to 100% of their annual cash retainer and fees into a variety of investment fund options, all with market-based returns, including an AEP stock fund. The Plan permits the non-employee directors to defer receipt until termination of service or for a period that results in payment commencing not later than five years after termination of service.

Stock Unit Accumulation Plan. In 2010 the Stock Unit Accumulation Plan for Non-Employee Directors awarded $123,000 in AEP stock units. These AEP stock units are credited to directors quarterly, based on the closing price of AEP Common Stock on the payment date. Amounts equivalent to cash dividends on the AEP stock units accrue as additional AEP stock units. AEP stock units are not paid to the director in cash until termination of service unless the director has elected to further defer payment for a period that results in payment commencing not later than five years after termination of service.

Insurance. AEP maintains a group 24-hour accident insurance policy to provide a $1,000,000 accidental death benefit for each director, $100,000 for each spouse of a director and $50,000 for all dependent children. The current policy, effective September 1, 2007 through September 1, 2012, has a premium of $48,175.

Stock Ownership. The Board considers stock ownership in AEP by Board members to be important. As noted above in Stock Unit Accumulation Plan, non-employee directors are required to defer all AEP stock units until termination of his or her directorship. As noted in Share Ownership of Directors and Executive Officers, each non-employee director of AEP owns more than 9,000 shares of AEP Common Stock and AEP stock units, except for Mr. Cordes, who was elected to the Board of Directors in September 2009.

Insurance

The directors and officers of AEP and the AEP System subsidiaries are insured, subject to certain exclusions and deductibles, against losses resulting from any claim or claims made against them while acting in their capacities as directors and officers. Such insurance, effective March 15, 2010 to March 15, 2011, is provided by: Associated Electric & Gas Insurance Services Ltd., Energy Insurance Mutual Ltd., Zurich American Insurance Company, AXIS Insurance Company, Arch Insurance Company, St. Paul Mercury Insurance Company (Travelers), Westchester Fire Insurance

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Company (ACE), Carolina Casualty Insurance Company (W.R. Berkley), RSUI Indemnity Company, U.S. Specialty Insurance Company (HCC Global), Scottsdale Indemnity Company (Nationwide), Arch Reinsurance, Ltd., National Union Fire Insurance Company (Chartis, formerly AIG), Allied World Assurance Company Ltd. (AWAC), Liberty Mutual Insurance Company, Houston Casualty Company (HCC Global), St. Paul Mercury Insurance Company (Travelers), Ariel Reinsurance Company, Ltd and Catlin Specialty Insurance Company (Catlin, Inc.). The total cost of this insurance is $4,324,832.

Fiduciary liability insurance provides coverage for AEP System companies and their affiliated trusts, their directors and officers, and any employee deemed to be a fiduciary or trustee, for breach of fiduciary responsibility, obligation, or duties as imposed under the Employee Retirement Income Security Act of 1974. Such insurance, effective March 15, 2010 to March 15, 2011, is provided by U.S. Specialty Insurance Company, AXIS Specialty Insurance Company, Energy Insurance Mutual Ltd., and Scottsdale Indemnity Company (Nationwide). The total cost of this insurance is $649,030.

2. Proposal to Ratify Appointment of Independent Registered Public Accounting Firm

The Audit Committee has appointed the firm of Deloitte & Touche LLP as the Company' s independent registered public accounting firm for 2011. Although action by the shareholders in this matter is not required, the Audit Committee believes that it is appropriate to seek shareholder ratification of this appointment in light of the critical role played by the independent registered public accounting firm in maintaining the integrity of Company financial controls and reporting, and will seriously consider shareholder input on this issue. Whether or not the appointment of Deloitte & Touche LLP is ratified by the shareholders, the Audit Committee may, in its discretion, change the appointment at any time during the year if it determines that such change would be in the best interests of the Company and its shareholders.

One or more representatives of Deloitte & Touche LLP will be in attendance at the annual meeting on April 26, 2011. The representatives will have the opportunity to make a statement, if desired, and will be available to respond to appropriate questions from shareholders.

Vote Required.

Approval of this proposal requires the affirmative vote of holders of a majority of the votes cast at the meeting.

Your Board of Directors recommends a vote **FOR** this Proposal 2.

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Audit and Non-Audit Fees

The following table presents fees for professional audit services rendered by Deloitte & Touche LLP for the audit of the Company' s annual financial statements for the years ended December 31, 2010 and December 31, 2009, and fees billed for other services rendered by Deloitte & Touche LLP during those periods.

	2010	2009
Audit Fees(1)	$11,245,000	$11,411,000
Audit-Related Fees(2)	664,000	1,680,000
Tax Fees(3)	220,000	275,000
TOTAL	$12,129,000	$13,366,000

(1) Audit fees in 2009 and 2010 consisted primarily of fees related to the audit of the Company' s annual consolidated financial statements, including each registrant subsidiary. Audit fees also included auditing procedures performed in accordance with Sarbanes-Oxley Act Section 404 and the related Public Company Accounting Oversight Board Auditing Standard Number 5 regarding the Company' s internal control over financial reporting. This category also includes work generally only the independent registered public accounting firm can reasonably be expected to provide.

(2) Audit related fees consisted principally of regulatory, statutory and employee benefit plan audits. The 2009 amount included required services related to a rate filing for one of the Company' s public utility subsidiaries.

(3) Tax fees consisted principally of tax compliance services. Tax compliance services are services rendered based upon facts already in existence or transactions that have already occurred to document, compute, and obtain government approval for amounts to be included in tax filings.

The Audit Committee has considered whether the provision of services other than audit services by Deloitte & Touche LLP and its domestic and global affiliates is compatible with maintaining independence, and the Audit Committee believes that this provision of services is compatible with maintaining Deloitte & Touche LLP' s independence.

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Audit Committee Report

The Audit Committee reviews AEP' s financial reporting process as well as the internal control over financial reporting on behalf of the Board. Management has the primary responsibility for the financial statements and the reporting process, including the system of internal control over financial reporting.

The Audit Committee met nine times during the year and held discussions, some of which were in private, with management, the internal auditor, and the independent auditor. Management represented to the Audit Committee that AEP' s consolidated financial statements were prepared in accordance with generally accepted accounting principles. Management has also concluded that the Company' s internal control over financial reporting was effective as of December 31, 2010. The Audit Committee has reviewed and discussed the consolidated financial statements and internal control over financial reporting with management, the internal auditor, and the independent auditor. The Audit Committee discussed with the independent auditor matters required to be discussed by Public Company Accounting Oversight Board (PCAOB) AU sec 380, Communication With Audit Committees.

In addition, the Audit Committee has discussed with the independent auditor its independence from AEP and its management, including the matters required by the applicable PCAOB requirements regarding receipt of the independent auditor' s communication with the Audit Committee concerning their independence. The Audit Committee has also received written materials addressing the independent auditor internal quality control procedures and other matters, as required by the NYSE listing standards.

In reliance on the reviews and discussions referred to above, the Audit Committee recommended to the Board, and the Board has approved, that the audited financial statements be included in AEP' s Annual Report on Form 10-K for the year ended December 31, 2010, for filing with the SEC.

Audit Committee Members
E. R. Brooks
Linda A. Goodspeed
Lionel L. Nowell, III, Chair
Sara Martinez Tucker
John F. Turner

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Policy on Audit Committee Pre-Approval of Audit and Permissible Non-Audit Services of the Independent Auditor

The Audit Committee' s policy is to pre-approve all audit and non-audit services provided by the independent auditor. These services may include audit services, audit-related services, tax services and other services. Pre-approval is provided for up to one year and any pre-approval is detailed as to the particular service or category of services and is subject to a specific limitation. The independent auditor and management are required to report to the Audit Committee at each regular meeting regarding the extent of services provided by the independent auditor in accordance with this pre-approval policy, and the fees for the services performed to date. The Audit Committee may also pre-approve particular services on a case-by-case basis. In 2010, all Deloitte & Touche LLP services were pre-approved by the Audit Committee.

3. Advisory Vote on Executive Compensation

The recently enacted Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010, or the Dodd-Frank Act, enables our shareholders to vote to approve, on an advisory (nonbinding) basis, the compensation of our named executive officers as disclosed in this proxy statement in accordance with the SEC' s rules.

As described in detail under the heading "Compensation Discussion and Analysis," our executive compensation programs are designed to attract, motivate, and retain our named executive officers, who are critical to our success. Under these programs, our named executive officers are rewarded for the achievement of annual and long-term goals. Please read the "Compensation Discussion and Analysis" beginning on page 26 for additional details about the 2010 compensation of our named executive officers.

The HR Committee continually reviews the compensation programs for our named executive officers to ensure they achieve the desired goals of aligning our executive compensation structure with our shareholders' interests and current market practices. As a result of its review process, the HR Committee maintains the following executive compensation practices:

A three-year performance period for our long-term incentive awards to encourage management to make decisions that are aligned with shareholders' interests;

A three-year relative total shareholder return measure, which constitutes 50% of the performance factor for our long-term incentive awards, to further align the compensation of our executives with our performance relative to our peers;

A Clawback Policy that allows the Board to recoup any excess incentive compensation paid to our named executive officers and other key members of our executive team if the financial results on which the awards were based are materially restated due to misconduct of the executive;

Elimination of tax gross-ups on perquisites, curtailment of personal use of Company aircraft and elimination of other perquisites, including company paid country club memberships; and

Elimination of the reimbursement and tax gross-up for excise taxes triggered under change in control agreements issued to new participants after October 2009.

We are asking our shareholders to indicate their support for our named executive officer compensation as described in this proxy statement. This proposal, commonly known as a "say-on-pay" proposal, gives our shareholders the opportunity to express their views on our named executive officers' compensation. This vote is not intended to address any specific item of compensation, but rather the overall compensation of our named executive officers and the philosophy, policies and practices described in this proxy statement. Accordingly, we will ask our shareholders to vote "FOR" the following resolution at the Annual Meeting:

"RESOLVED, that the compensation paid to the named executive officers, as disclosed in the Company' s Proxy Statement for the 2011 Annual Meeting of Shareholders pursuant to rules of the SEC, including the Compensation Discussion and Analysis, compensation tables and related narrative disclosure is hereby APPROVED."

The say-on-pay vote is advisory, and therefore not binding on the Company, the HR Committee or our Board of Directors. Our Board of Directors and our HR Committee value the opinions of our shareholders and to the extent there is a significant vote against the named executive officer compensation as disclosed in this proxy statement, we will consider our shareholders' concerns and the HR Committee will evaluate whether any actions are necessary to address those concerns.

Vote Required.

Approval of this proposal requires the affirmative vote of holders of a majority of the votes cast at the meeting.

Your Board of Directors recommends a vote **FOR** this Proposal 3.

4. Advisory Vote on the Frequency of an Advisory Vote on Executive Compensation

The Dodd-Frank Act also enables our shareholders to indicate how frequently we should seek an advisory vote on the compensation of our named executive officers. By voting on this Proposal 4, shareholders may indicate whether they would prefer an advisory vote on named executive officer compensation once every one, two, or three years. Pursuant to the Dodd-Frank Act, this frequency vote is an advisory vote only, and it is not binding on AEP or the Board of Directors.

Although the vote is non-binding, the Board of Directors values the opinions of the shareholders and will consider the outcome of the vote when determining the frequency of the shareholder vote on executive compensation.

After careful consideration of this Proposal, our Board of Directors has determined that an advisory vote on executive compensation that occurs every year is the most appropriate alternative for AEP, and therefore our Board of Directors recommends that you vote for a one-year interval for the advisory vote on executive compensation. In formulating its recommendation, our Board of Directors considered that an annual advisory vote on executive compensation will allow our shareholders to provide us with their direct input on our compensation philosophy, policies and practices as disclosed in the proxy statement every year. Additionally, an annual advisory vote on executive compensation is consistent with our approach of seeking input from, and engaging in discussions with, our shareholders on corporate governance matters.

Vote Required.

The advisory vote regarding the frequency of the shareholder vote shall be determined by a plurality of the votes cast.

Your Board of Directors recommends a vote **FOR ONE YEAR** on proposal 4 regarding the frequency of the shareholder vote to approve the compensation of the named executive officers as required by SEC rules.

Other Business

The Board of Directors does not intend to present to the meeting any business other than the election of directors, the ratification of the appointment of the independent registered public accounting firm, the advisory vote on the compensation of the named executive officers as disclosed in this proxy statement and whether the advisory vote on the compensation of the named executive officers should occur every one, two or three years.

If any other business not described herein should properly come before the meeting for action by the shareholders, the persons named as proxies on the proxy card or their substitutes will vote the shares represented by them in accordance with their best judgment. At the time this proxy statement was printed, the Board of Directors was not aware of any other matters that might be presented.

Compensation Discussion and Analysis

Highlights for 2010

Economic conditions remained extremely challenging for the Company in 2010. Power demand remained at depressed levels overall despite extremely favorable weather that bolstered retail sales. Large industrial sales began to gradually improve at the end of the second quarter but commercial sales remained flat for much of the year. The influx of shale gas also negatively impacted both the price and volume of AEP' s off-system sales. As a result of these difficult conditions, the Company undertook a restructuring that included both voluntary and involuntary employee severance programs in an effort to reduce expenses, adjust the Company' s workforce to fit reduced capital and operation and maintenance budgets, and meet the Company' s earnings commitments to shareholders. Largely as a result of these programs, the Company' s 2010 ongoing earnings improved in the second half of the year to reach $3.03 per share for 2010, which slightly exceeded the midpoint of our earnings per share (EPS) guidance range and EPS target of $3.00 per share. In addition, AEP completed 2010 without a work-related fatal employee accident, which is another significant achievement.

The HR Committee initially established threshold (0 percent of target payout), target and maximum (200 percent of target payout) points at $2.80, $3.00 and $3.20 per share, respectively. Subsequently, based on management' s recommendation, the HR Committee adopted a more demanding ongoing earnings threshold of $3.00 per share. This threshold required earnings of at least $3.00 per share for any annual incentive funding or payouts. In setting the $3.00 target, the HR Committee considered the dilutive effect of the 2009 equity issuance and the extraordinarily difficult economic conditions at the time. This was a $0.03 (or 1 percent) increase from AEP' s 2009 ongoing earnings of $2.97 per share.

AEP' s ongoing 2010 EPS of $3.03 was above the midpoint of our earnings guidance for the year and resulted in funding of 113.5 percent of the target award pool for 2010. This near target annual incentive award funding is a substantial improvement from 2009, which was a year for which no annual incentive awards were paid to executive officers. This was due to the significant EPS dilution from the Company' s equity issuance, which reduced EPS substantially below target, and to two fatal work related accidents.

In 2010, the Company continued to closely align executive officers' total compensation opportunity with shareholders' interests by providing a substantial percentage of it in the form of performance-based stock compensation. AEP' s three-year performance unit awards account for approximately 67 percent of Mr. Morris' total compensation opportunity. These performance units are tied to AEP' s three year cumulative EPS and three year total shareholder return relative to the electric utility and multi-utility companies in the S&P 500.

As a result of AEP' s March 2009 equity issuance, the cumulative EPS score for the 2008-2010 performance units was below expectations at 34.0% of target. However, the relative total shareholder return measure recovered by the end of the performance period to the 43rd percentile of the comparator group, which produced a score of 77.7% of target. The EPS and TSR scores combined to produce an overall score of 55.8% of target for the 2008-2010 performance period. As a result, 55.8% of the 2008-2010 performance units outstanding at year-end vested.

The HR Committee recognizes that the Company' s executive compensation levels and practices are a subject of interest and potential concern for the Company' s stakeholders, including its shareholders, regulators and customers. As such, the HR Committee regularly reviews best practices in executive compensation and has made the changes it believes are necessary to keep the Company' s executive compensation levels and practices both market competitive and in line with best practices. For many years, the Company has had stock ownership requirements for its executive officers, issued performance-based short-term and long-term incentive awards, and has had a policy that allows the Company to claw back incentive compensation in certain circumstances. In addition, the HR Committee has made several changes to the Company' s executive compensation program in the last two years, including:

- Freezing salaries for executives at 2008 levels for 2009 and 2010, other than for promotional increases and salary increases to offset the elimination of subsidiary company board fees,

- Freezing target annual incentive opportunities for each salary grade, expressed as a percentage of base pay, at the 2008 level for 2009 and 2010,

- Freezing the target long-term incentive opportunities for each salary grade, expressed as a grant date fair value, at the 2008 level for 2009, 2010 and the most recent 2011 awards,

- Granting all new long-term incentive awards with change in control provisions that include a double trigger that provides vesting of awards only in the event of a change in control combined with a separation from service,

- Eliminating company paid country club memberships,

- Generally eliminating personal use of Company provided aircraft, to the extent that such use has an incremental cost to the Company, except for Mr. Morris who negotiated this as part of his employment agreement. This change also precludes successor CEOs from using company provided aircraft for personal use,

- Eliminating tax gross-ups, except on relocation benefits, Eliminating the reimbursement and tax gross-up for excise taxes triggered under change in control agreements issued to new participants after October 2009.

The HR Committee reviewed the Company’ s compensation policies and practices for all employees, including executive officers, and determined that the compensation programs are not reasonably likely to have a material adverse effect on the Company. See Compensation Risk on page 9 for additional information.

Overview

The HR Committee oversees and determines AEP’ s executive compensation. The HR Committee makes recommendations to the independent members of the board of directors about the compensation of the Chief Executive Officer, and those independent board members determine the CEO’ s compensation.

AEP’ s executive compensation programs are designed to:

Attract and retain a superb leadership team with market competitive compensation and benefits;

- Reflect AEP' s financial and operational size and the complexity of its multi-state operations;

- Emphasize performance-based compensation over base salary by providing a substantial majority of executive officers' total compensation opportunities in the form of incentive compensation;

- Align the interests of the Company' s executive officers with those of AEP' s shareholders by providing a substantial percentage of the total compensation opportunity for executive officers in the form of stock based compensation that has a value linked to AEP' s share price and other shareholder return measures;

- Support the implementation of the Company' s business strategy by tying annual incentive awards to earnings per share targets and to the achievement of specific operating and strategic objectives;

- Motivate and reward outstanding team and individual performance; and

- Promote the stability of the management team by creating strong retention incentives with multi-year vesting schedules for long-term incentive compensation, and requiring executives to meet stock ownership requirements.

Overall, AEP' s executive compensation program is intended to create a total compensation opportunity that, on average, is equal to the median of AEP' s Compensation Peer Group of other utility companies and industrial companies, as described under Compensation Peer Group on page 29. The HR Committee' s independent compensation consultant, Pay Governance LLC (Pay Governance) participates in HR Committee meetings, assists the HR Committee in developing the compensation program and has an opportunity to meet with the HR Committee in executive session without management present during all meetings. See the Human Resources Committee Report on page 46 for additional information about the independence of Pay Governance' s advice to the HR Committee.

Compensation Program Design

The compensation program for executive officers includes base salary, annual incentive compensation, long-term incentive compensation, a comprehensive benefits program and limited perquisites. The HR Committee provides a balance of short-term and long-term incentive compensation that is consistent with the compensation mix provided by AEP' s Compensation Peer Group. For AEP' s annual incentive compensation, the HR Committee balances meeting AEP' s ongoing earnings per share target with other objectives, such as safety.

The HR Committee chose ongoing earnings per share as the funding measure for the annual incentive plan because it is strongly correlated with shareholder returns, largely reflects management' s performance in operating the Company and is the primary measure by which the Company communicates its actual and expected future financial performance to the investment community. The EPS measure is also well understood by both our shareholders and employees. We also believe that EPS growth is the primary means for the Company to create long-term shareholder value.

AEP’ s long-term incentive compensation is tied to longer-term shareholder return objectives to maintain an appropriate focus on creating sustainable long-term shareholder value. Specifically, in 2010, the HR Committee awarded performance units to executive officers with three-year performance measures tied to AEP’ s total shareholder return, relative to all the electric and multi-utility companies in the S&P 500 Index, and cumulative earnings per share relative to a board approved target. A cumulative earnings measure was chosen to ensure that the total earnings for all three years contribute equally to the award calculations, as opposed to assessing performance for each of the three years independently, which could encourage the sacrificing of earnings in one year to better ensure the achievement of earnings objectives in other years. The HR Committee also chose a total shareholder return measure for these awards to provide an external performance comparison that reflects the effectiveness of management' s strategic decisions and actions over a three-year period relative to other large companies in our industry. The HR Committee also uses long-term incentives as a retention tool to foster management continuity by subjecting these awards to a three-year vesting period.

The HR Committee annually reviews the mix of base salary, annual incentive and long-term incentive compensation opportunity provided to executives. For 2010, 84 percent of the total compensation opportunity for the Chief Executive Officer and at least 80 percent of that for the other named executive officers was at risk in the form of incentive compensation. More than 66 percent of the 2010 target compensation opportunity for the CEO and between 65 percent and 78 percent of that for the other named executive officers is in the form of long-term, stock based incentive compensation. The ultimate value that executives realize from that compensation opportunity is therefore closely linked to AEP' s share price and dividends.

The HR Committee targets the total compensation opportunity for executives within a range of plus or minus 15 percent of the median of the Compensation Peer Group, which is the range of compensation that is generally considered to be market competitive by the HR Committee' s independent compensation consultant. The HR Committee chose the median as a target because it corresponds to the Company' s near median position within the Compensation Peer Group for various size measures, such as revenue, number of employees, and total assets. To the extent that the total compensation opportunity for an executive is above or below the peer group median, the HR Committee adjusts elements of pay over time to bring their total compensation opportunity into the market competitive range. Each year the HR Committee' s compensation consultant completes an annual executive compensation study. As of September 2010, this study found that, in aggregate, executive base salaries, total cash compensation (base salary and annual incentive compensation) and total direct compensation (total cash compensation and long-term incentives) were all well within the market competitive range.

Compensation Peer Group

The HR Committee annually reviews AEP' s executive compensation relative to a peer group of companies that represent the talent markets with which AEP must compete to attract and retain executives. This Compensation Peer Group is reviewed annually by the HR Committee in consultation with its independent compensation consultant. The Compensation Peer Group is chosen based on comparability in size to AEP in terms of revenues, total assets, market capitalization, number of employees and business complexity.

The Compensation Peer Group is selected to consist of an approximately equal number of utility and industrial companies. The utility companies are selected to provide a more direct comparison to companies with businesses similar to AEP' s. The HR Committee includes industrial companies outside the utility industry because AEP must also compete with industrial companies to attract and retain executives. In addition, because AEP is one of the largest U.S. utility companies based on assets and employees, the Company also includes the industrial companies in the peer group to increase the median level of assets and employees in the peer group to more closely compare to AEP. In addition to the factors mentioned above for all peer companies, the HR Committee considers the one and three year total shareholder return of potential industrial companies in selecting the peer group.

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For 2010 the Compensation Peer Group consisted of the 14 large and diversified utility industry companies and the 12 general industry companies shown in the table below. The Compensation Peer Group is unchanged from the prior year.

AEP' s Compensation Peer Group

Energy (14 Companies)	***General Industry (12 Companies)***
Centerpoint Energy, Inc.	3M Company
Constellation Energy Group, Inc.	Bristol-Myers Squibb Company
Dominion Resources, Inc.	Caterpillar Inc.
Duke Energy Corporation	CSX Corporation
Edison International	Goodyear Tire & Rubber Company
Entergy Corporation	Northrop Grumman Corporation
Exelon Corporation	PPG Industries, Inc.
FirstEnergy Corp.	Schlumberger N.V.
NextEra Energy, Inc.	Sunoco, Inc.
PG&E Corporation	Textron Inc.
Public Service Enterprise Group Inc.	Union Pacific Corporation
Sempra Energy	Weyerhaeuser Company
Southern Company (The)	

The table below shows that, at the time the Compensation Peer Group data was collected in early 2010, AEP' s revenue, market capitalization, number of employees and total shareholder return for both one-year and three year periods were all near the 50th percentile of the combined peer group, while AEP' s Total Assets were above the 75th percentile.

2010 Compensation Peer Group

	Revenue ($ million)	Total Assets ($ million)	Market Capitalization ($ million)	Employees	Total Shareholder Return 1 Year	Total Shareholder Return 3 Year
Summary Statistics						
Combined Peer Group						
25th Percentile	$11,119	$24,030	$ 10,281	14,075	6 %	-33 %
50th Percentile	$13,771	$30,630	$ 16,589	19,287	18 %	-2 %
75th Percentile	$17,064	$42,518	$ 26,994	37,925	31 %	12 %
Utility Industry Median	$12,431	$39,404	$ 15,603	15,091	10 %	1 %
General Industry Median	$17,555	$27,143	$ 18,634	41,125	32 %	-10 %
AEP	**$13,489**	**$48,348**	**$ 17,250**	**21,673**	**22 %**	**-5 %**

The HR Committee' s executive compensation consultant annually provides the HR Committee with an executive compensation study covering all executive officer positions and many other executive positions based on survey information for the Compensation Peer Group. The methodology and job matches used in this study were determined by Pay Governance based on descriptions of each executive' s responsibilities and are reviewed with the HR Committee. The standard benchmark is the median value of compensation paid by the Compensation Peer Group but the HR Committee' s compensation consultant does use other benchmarks if, in its judgment, such other benchmarks provide a better comparison based on the specific scope of the job being matched.

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Broader energy and general industry data is used when sufficient data was not available in the Compensation Peer Group to provide a comparison, as was the case for Mr. Akins' and Mr. Powers' positions in 2010. In 2010, Pay Governance used the 75th percentile of all energy companies in the Towers Watson database with a 15 percent premium as the market benchmark for Mr. Akins' position to provide a better comparison to both the size and breadth of his responsibilities. The 75th percentile of the utility peers was used as the market benchmark for Mr. Powers' position to provide a better comparison to the size and scope of his responsibilities, which only exists in utility companies. These AEP positions have responsibility for substantially larger groups than matching positions in the Compensation Peer Group so good compensation benchmarks could not be provided from this sample of companies.

Executive Compensation Program Detail

Executive Compensation Component Summary. The following table summarizes the major components of the Company's Executive Compensation Program.

Component	Purpose	Key Attributes
Base Salary	To provide a market-competitive and consistent minimum level of compensation	No regular merit increases were provided to AEP executive officers in 2010. However, salary increases were provided to 2 of the named executive officers who were promoted and to each of the named executive officers to offset eliminated subsidiary company director fees. Generally, salary increases are awarded by the HR Committee based on: The Company's merit budget, Sustained individual performance and competencies as assessed by each executive's direct manager with input from other senior managers and communicated via written evaluations, performance ratings and merit increase recommendations, The responsibilities, experience and future potential of each executive officer, Reporting relationships, and The impact that any change in base salary may have on other pay elements and the market competitiveness of the executive's total compensation.

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Component	Purpose	Key Attributes
Annual Incentive Compensation	To intensify executive officer focus on annual performance objectives that are critical to AEP' s success To communicate these critical annual performance objectives throughout the Company in a way that distinguishes them from other objectives and makes their importance clear to all Ongoing earnings per share was the 2010 funding measure, Four equally weighted categories of other performance objectives were established for 2010 to communicate and align executive and employee efforts to the goals of the company throughout 2010. Although this purpose was accomplished, these performance objectives did not impact 2010 annual incentive compensation, due to the Company' s reorganization and cost cutting initiative that caused the Company to change its incentive program during the year: Safety and health, Operations, Regulatory, and Strategic initiatives.	Annual incentive targets are established by the HR Committee based on competitive compensation information provided by the HR Committee' s compensation consultant Actual awards may vary from 0 percent to 200 percent of each executive' s annual incentive target Annual incentive funding is created only if the Company exceeds ongoing EPS threshold of $3.00 for 2010 Individual awards are then determined by the HR Committee based on: Each executive' s calculated bonus opportunity, and A subjective evaluation of their individual performance for the prior year.

Component	Purpose	Key Attributes
Long-Term Incentive Compensation	To motivate AEP management to maximize shareholder value by linking a substantial portion of potential executive compensation directly to shareholder returns To help ensure that Company management remains focused on longer-term results, which the HR Committee considers to be essential given the large long-term investments in physical assets required in our business To reduce executive turnover and maintain management consistency The specific performance objectives used for long-term incentive awards grant for 2010 are: Three-year cumulative earnings per share relative to a board approved target, and Three-year total shareholder return relative to the utilities in the S&P 500.	The HR Committee provided long-term incentive awards effective for 2010 in the form of three-year performance units The HR Committee establishes award guidelines for each executive salary grade based on total compensation practices for similar positions in AEP' s Compensation Peer Group Individual long-term incentive awards are primarily based on: Individual performance, Award guidelines for each salary grade established by the HR Committee, Market competitive compensation levels, Each executive officer' s future potential for advancement.

BASE SALARY. In light of extremely difficult economic conditions, the HR Committee did not award merit based salary increases to any of the named executive officers for 2009 or 2010. However, the HR Committee did provide promotional increases during this two year period. Mr. Akins received a $50,000 promotional salary increase effective January 1, 2010 when he was assigned oversight responsibility for AEP' s Commercial Operations group in addition to his existing responsibilities. As reported in last year' s proxy statement, Mr. Tierney received a $50,000 salary increase in October 2009, in conjunction with his promotion to Chief Financial Officer.

The salary of each of the named executive officers was also increased effective January 1, 2010 to offset the elimination of subsidiary company director fees. These salary increases were $15,000, $15,000, $11,400, $11,400, $12,600 and $9,000 for Messrs. Morris, Tierney, English, Powers, Akins and Ms. McCellon-Allen, respectively.

Effective January 1, 2011, the named executive officers received merit increases generally in the three percent range. In addition, Mr. Akins' received a $200,000 increase in conjunction with his promotion to AEP' s President, which brought his base salary to $750,000. Messrs. Tierney, Powers and Akins were the three final internal candidates considered by the Board of Directors as potential successors for Mr. Morris as CEO. Because the multi-year assignments Messrs. Tierney and Powers undertook as part of the succession planning and development process for the CEO position gave them experience and broad exposure that increased their value to AEP, as well as to other companies, their base salaries were both increased to $600,000.

ANNUAL INCENTIVE COMPENSATION.

Annual Incentive Targets. The HR Committee, in consultation with its independent compensation consultant and Company management, establishes the annual incentive targets for each executive officer primarily based on compensation benchmark studies. For 2010 the HR Committee established the following annual incentive targets for each of the positions held by the named executive officers:

110 percent of base earnings for the CEO position (Mr. Morris),

75 percent of base earnings for the CFO and COO positions (Messrs. Tierney and English),

70 percent of base earnings for the President – AEP Utilities position (Mr. Powers), and

65 percent of base earnings for the EVP Generation (Mr. Akins) and for Ms. McCellon-Allen (President – SWEPCo) due to her previous service in EVP level positions.

Funding For Annual Incentive Plan. In 2010 AEP produced ongoing EPS of $3.03, which was above the midpoint of AEP' s earnings guidance for the year. This resulted in annual incentive funding of 113.5% of the target award pool. This result was calculated by interpolation between a 100% of target payout at EPS of $3.00 and a 200% of target payout at EPS of $3.20, using EPS rounded to three decimal places of $3.027. There were no fatal employee accidents, so the fatality deduction (discussed below) did not apply for 2010.

For 2010, earnings per share reported in AEP' s financial statements were $0.50 per share lower than ongoing earnings, primarily because of:

1. Charges incurred related to the cost-reduction program implemented in May 2010 ($185 million net of tax),
2. The disallowance by the Virginia State Corporation Commission of the recovery of $54 million related to the Mountaineer Plant carbon capture and storage project ($34 million net of tax), and
3. The effect of the enactment of the federal Patient Protection and Affordable Care Act, resulting in an unfavorable $21 million change in the tax treatment of post-employment health care costs associated with future reimbursement of Medicare Part D retiree prescription drug benefits.

See our Form 8-K filed on January 28, 2011 announcing 2010 fourth quarter and year-end earnings for a reconciliation of ongoing and reported EPS.

Annual Performance Objectives. For 2010 the HR Committee developed a balanced scorecard to tie annual incentive awards for AEP' s executive team to four areas of performance: safety, operating performance, regulatory performance and strategic initiatives. This balanced scorecard served as a tool to communicate and align the efforts of executive officers and other employees with the performance measures included on the scorecard. The balanced scorecard focused on the following four categories.

Safety and Health. Maintaining the safety of AEP employees, customers and the general public is always the primary consideration, and safety is an AEP core value. We measure this using employee and contractor recordable case rate in accordance with the methodology prescribed by the Occupational Safety and Health Administration (OSHA) for recordable incidents. We also measure incident severity rate portion by the number of lost and restricted duty work days per 200,000 work hours. Wellness improvement was measured by improvement in the completion rate for AEP' s Wellness Program by employees and spouses participating in AEP' s medical plan. In addition to these measures, the HR Committee also established a fatality deduction, which is discussed below.

Operations. The HR Committee also tied 25% of the scorecard to the operating performance of AEP' s assets. This category measures the reliability of our wires assets, the equivalent forced

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outage rate for our generating plants and our performance on planned generating plant outages. The reliability measure is the system average incident duration index (SAIDI), which is a standard measure in our industry. The equivalent forced outage rate is an indicator of the extent to which our plants ran reliably during the year. The Operations category also included AEP' s environmental goal, which is a measure of the number of major formal notices of violation of environmental regulations.

Regulatory. Investments in our business depend on obtaining satisfactory and appropriate rates of return on our regulated businesses in all the jurisdictions in which we operate. Therefore, the HR Committee tied 25% of the scorecard to AEP' s overall success in achieving rate recovery in regulatory proceedings at the Federal Energy Regulatory Commission and state public utility commissions. In 2010 AEP secured $329 million in new rate recovery.

Strategic. The remaining 25% of the executive council scorecard was tied to strategic initiatives for 2010, including an environmental policy, planning and leadership measure. Strategic initiatives also included Diverse Candidate Placement Rate which measures the rate of AEP' s female and minority hiring compared to the availability of female and minority candidates for the position opportunities AEP expected to have available in 2010.

The above balanced scorecard goals were maintained throughout the year and produced an overall score above target for 2010.

2010 Award Calculation. Due to AEP' s reorganization and cost cutting initiative it was impractical to revise and track all the goals established for each of AEP' s business units for 2010. In light of these unusual circumstances, in July 2010 all business unit scorecards were suspended for the year and replaced with the executive council scorecard for all employees. Because all business units, including AEP' s Executive Council, shared the same goals for 2010, and those goals were measured on a company-wide basis, there was no differentiation in incentive plan funding between business units. As a result, the score was the same for each business unit, including executive officers. Therefore, the annual incentive funding was equal to the EPS Funding score for all groups.

Deductions. The HR Committee again established a fatality deduction for 2010 that would have deducted 25% of target score from the final score for executive officers if the Company experienced a fatal work related employee accident. Because AEP did not have a work-related employee fatality in 2010, the fatality deduction did not apply.

The calculated bonus opportunity is shown in the chart below for each named executive officer. This is the starting point for determining annual incentive awards. The HR Committee then evaluates the individual performance of each named executive officer to determine the actual awards, which are also shown in the table below for 2010.

Name	2010 Base Earnings		Annual Incentive Target %			Overall Performance Score			Calculated Bonus Opportunity	2010 Actual Awards
Michael G. Morris	$1,265,346	x	110	%	x	113.5	%	=	$1,579,785	$1,579,785
Brian X. Tierney	$464,577	x	75	%	x	113.5	%	=	$395,471	$425,000
Robert P. Powers	$521,663	x	70	%	x	113.5	%	=	$414,461	$420,961
Nicholas K. Akins	$512,121	x	65	%	x	113.5	%	=	$377,818	$365,000

Carl L. English										
	$561,663	x	75	%	x	113.5	%	=	$478,116	$450,000
Venita McCellon-Allen										
	$409,208	x	65	%	x	113.5	%	=	$301,893	$283,780

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The HR Committee believes that annual incentive compensation should not be based purely on a formulaic calculation, such as that shown in the Calculated Bonus Opportunity column above, but should instead be adjusted from this starting point to reflect each executive' s individual performance and contribution. Based on recommendations from each executive officer' s manager focusing on the subjective evaluation of their individual performance and contribution, particularly with respect to the executive council scorecard goals, the HR Committee approved the annual incentive awards shown in the Actual Awards column for 2010.

LONG-TERM INCENTIVE COMPENSATION.

AEP annually reviews the mix of long-term incentive compensation it provides its executives. The HR Committee grants long-term incentive awards on a fixed annual cycle that currently takes place at its December meeting following its annual executive compensation review. It is a long-standing HR Committee practice to consider the impact of any recent and upcoming Company announcements and financial disclosures that may impact AEP' s share price, as well as AEP' s current stock price itself, when determining the number of shares, units or options to grant under AEP' s long-term incentive program.

The HR Committee establishes award guidelines for each executive salary grade based on market competitive total compensation for similar positions in AEP' s Compensation Peer Group. Individual long-term incentive awards are determined by the HR Committee, or, for the CEO, by the independent members of the Board. These determinations are made based on:

Award guidelines for each salary grade established by the HR Committee, which creates an overall award pool that AEP management and the HR Committee use in determining awards,

Individual performance assessments. However, any positive discretionary adjustments based on individual performance must generally be offset by negative adjustments to avoid exceeding the above award pool,

Individual executive' s total direct compensation relative to market competitive compensation for his or her position as shown in the annual executive compensation study conducted by the HR Committee' s executive compensation consultant, and

The executive officers' future potential for advancement.

The HR Committee also regularly reviews tally sheets for the named executive officers that show the potential future payout of outstanding equity awards. These tally sheets show the extent to which the value of the potential payout from all outstanding equity awards is linked to changes in AEP' s stock price and the value likely to be paid from all outstanding equity awards taking the Company' s performance and condition into consideration. The tally sheets also show whether the value that executive officers have already received from vested equity awards is so large as to significantly reduce the need for or effectiveness of any future equity awards. The HR Committee may reduce equity awards to any or all executives if they were to find that any of these considerations or any other consideration warrant doing so.

Performance Units.

The HR Committee granted performance unit awards, effective in 2010 to each named executive officer as follows:

Name	Number of Performance Units Granted
Mr. Morris	155,000
Mr. Tierney	35,060
Mr. Powers	36,810
Mr. Akins	27,040
Mr. English	52,590
Ms. McCellon-Allen	24,540

These performance unit awards provide total direct compensation to executives in an aggregate that is within the market competitive range. Differences between the awards for individual executives primarily reflect differences in salary grade. Mr. Akins' award includes 750 units granted on January 26, 2010 because of a promotional increase in his salary grade.

Recipients must remain employed by AEP through the end of the vesting period to receive a payout unless they retire, are severed by the Company as part of a consolidation, restructuring or downsizing, in which case they receive a prorated payout based on the number of months they actively worked or are terminated in conjunction with a change in control. Dividends are reinvested in additional performance units. The total number of performance units held at the end of the performance period is multiplied by the weighted score for the two performance measures shown below to determine the award payout; however, the maximum score for each performance measure is 200 percent.

Performance Measures for 2010 – 2012 Performance Units

Performance Measure	Weight	Threshold Performance	Target Performance	Maximum Payout Performance
3-Year Cumulative Earnings Per Share	50 %	\$8.39 (0% payout)	\$9.32 (100% payout)	\$10.25 (200% payout)
3-Year Total Shareholder Return vs. S&P Electric and Multi Utilities	50 %	20th Percentile (0% payout)	50th Percentile (100% payout)	80th Percentile (200% payout)

On December 31, 2010 performance units granted for the 2008−2010 performance period vested. The combined score for the 2008-2010 performance period was 55.8% of target. See page 56 under the Option Exercises and Stock Vested Table for additional information about the vesting of these performance units.

Restricted Stock Units.

In August 2010 the HR Committee granted 41,380 restricted stock units to each of Messrs. Akins, Powers and Tierney and Ms. McCellon-Allen. These executives were the four internal candidates considered as likely successors to AEP' s CEO position. These awards had a grant date fair value of $1,500,025 and will vest, subject to the participant' s continued AEP employment, in equal installments on the third, fourth and fifth anniversary of the grant date.

2011 Long-Term Incentive Awards.

In keeping with the HR Committee' s long-standing practice, in December 2010 it granted long-term incentive awards effective January 1, 2011 to the named executive officers. These awards

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were granted as part of AEP' s regular year-end grant date cycle. The grant date fair value was comprised of 60% performance unit awards for the 2011-2013 performance and vesting period and 40% restricted stock units (RSUs). The RSUs vest, subject to the executive' s continued employment, in three equal installments on May 1, 2012, May 1, 2013 and May 1, 2014, respectively. The HR Committee changed its practice from granting long-term incentive awards exclusively in performance units to better ensure retention of AEP' s management team following a nearly 11.5 percent overall reduction in employment at all levels of the organization and in anticipation of a change in AEP' s leadership in 2011 with the planned retirement of Mr. Morris. In addition, RSUs were added to:

- Better reflect the mix and diversity of long-term incentive awards provided by the companies in AEP' s Compensation Peer Group, and

- Provide a more consistent retention incentive during periods of economic instability.

In addition, both the 2011 performance unit and restricted stock unit awards were granted with change in control provisions that include a double trigger that provides earlier vesting of awards only in the event of a change in control combined with a separation from service. The restricted stock unit awards granted for 2011 also include a two year post retirement holding requirement for senior executives who are subject to mandatory retirement.

Stock Ownership Requirements.

The HR Committee believes that linking a significant portion of an executive' s financial rewards to the Company' s success, as reflected by the value of AEP stock, gives the executive a stake similar to that of the Company' s shareholders and encourages long-term management strategies that benefits shareholders. Therefore, the HR Committee requires senior executives (currently 46 individuals) to accumulate and hold a specific amount of AEP common stock or stock equivalents. The HR Committee annually reviews the minimum stock ownership levels for each executive salary grade and periodically adjusts these levels. Executives are generally expected to achieve their stock ownership requirements within five years. Due to promotions and changes in ownership requirements, executives may have multiple stock ownership requirements.

AEP' s stock ownership requirements are specified as a fixed number of shares or share equivalents for executives in each salary grade. At the time the stock ownership requirements were established, their value was equal to three times base salary for the CEO and two to two and one-half times base salary for the other named executive officers. The highest minimum stock ownership requirement assigned to each of the named executive officers, and their holdings at December 31, 2010, are shown in the table below.

Name	Highest Minimum Stock Ownership Requirement as of 12/31/2010 (Shares)	AEP Stock and Share Equivalent Holdings on 12/31/2010	
Mr. Morris	109,300	452,100	(1)

Mr. Tierney	52,700	94,680
Mr. Powers	52,700	103,442
Mr. Akins	35,300	72,494
Mr. English	62,900	85,914
Ms. McCellon-Allen	35,300	76,655

(1) Includes 66,667 unvested restricted shares that will vest, subject to Mr. Morris' s continued employment, on November 30, 2011.

If a participant has failed to meet all of their minimum stock ownership requirements, that executive' s performance units are mandatorily deferred into AEP Career Shares to the extent necessary to meet such requirements. AEP Career Shares are phantom stock units whose rate of return is equivalent to the total return on AEP stock with dividends reinvested. In addition, to the extent an executive has not met a minimum stock ownership requirement within five years of the date it was assigned, the executive is subject to:

- Mandatory deferral into AEP Career Shares of up to 50% of their annual incentive compensation award, and

- A requirement to retain the AEP shares realized through stock option exercises (net of shares redeemed to satisfy exercise costs and tax withholding requirements).

AEP Career Shares are not paid to participants until after their AEP employment ends.

BENEFITS.

AEP generally provides the same health and welfare benefits to named executive officers as it provides to other employees. AEP also provides the named executive officers with either four or five weeks of paid vacation.

AEP' s named executive officers participate in the same pension and savings plans as other eligible employees. These include tax-qualified and non-qualified defined contribution and defined benefit plans, as well as a Stock Ownership Requirement Plan that AEP maintains to provide a tax deferred method for senior executives to meet their minimum stock ownership requirements. AEP' s non-qualified retirement benefit plans are largely designed to provide "supplemental benefits" that would otherwise be offered through the tax-qualified plans except for the limits imposed by the Internal Revenue Code on those tax-qualified plans. As a result, the non-qualified plans allow eligible employees to accumulate higher levels of replacement income upon retirement than would be allowed under the tax-qualified plans alone.

The HR Committee recognizes that the non-qualified plans result in the deferral of the Company' s income tax deduction until such benefits are paid, but the HR Committee believes that executives generally should be entitled to the same retirement benefits, as a percentage of their eligible pay, as other employees and that these benefits are prevalent among similar companies.

The non-qualified plans also provide contractual benefits such as the starting balance credit of $2,100,000 and an increased credit rate under AEP' s pension program that Mr. Morris negotiated as part of his employment contract when he joined AEP. The increased pension benefits were provided to Mr. Morris to replace pension benefits that he otherwise could have earned from his prior employer. Some executive officers that were recruited to AEP have also negotiated additional years of credited service or an increased credit rate to offset pension benefits that they would have been able to earn from prior employers due to their length of service to those companies.

The Company and the HR Committee believe that AEP' s continued use of its qualified and non-qualified retirement plans (including the enhancements offered through the nonqualified plans) is consistent with competitive practice and necessary to attract executives. The HR Committee does, however, limit both the amount and types of compensation that are included in the qualified and non-qualified retirement plans because it believes that compensation over certain limits and certain types of compensation should not be further enhanced by including it in retirement benefit calculations. Therefore:

- Long-term incentive compensation is not included in the calculations that determine retirement and other benefits under AEP' s benefit plans, The cash balance formula of the AEP Supplemental Benefit Plan limits eligible compensation to the greater of $1 million or twice the participant' s base salary, and

Eligible compensation is also limited to $2 million under the non-qualified Supplemental Retirement Savings Plan.

AEP provides group term life insurance benefits to all employees, including the named executive officers, in the amount of two times their base salary.

For executives who relocate, AEP provides relocation assistance that is intended to offset their moving expenses. It includes reimbursement of expenses related to the purchase and sale of a home; the purchase of their home at its appraised value if it does not sell within 90 days or a 2% home sale bonus if it does sell; a payment to offset a loss on sale of their existing home, if applicable; and a fixed payment for travel costs, temporary living expenses and miscellaneous relocation expenses. This policy enables AEP to obtain high quality new hires and to relocate internal candidates as needed.

PERQUISITES.

AEP provides limited perquisites that help executives conduct Company business. The HR Committee annually reviews the perquisites provided by the Company to ensure that they are efficient and effective uses of AEP' s resources. The HR Committee also periodically reviews the value of perquisites provided to each named executive officer.

During 2010 the Company provided personal use of corporate aircraft to Mr. Morris. While the HR Committee believes that the enhanced security, travel flexibility and reduced travel time that corporate aircraft provide for personal travel benefits the Company, the HR Committee is also sensitive to concerns regarding the expense of corporate aircraft and the public perception regarding personal use of such aircraft. Accordingly, effective October 2009, the HR Committee generally prohibited personal use of corporate aircraft that has an incremental cost to the Company, except for Mr. Morris, who negotiated the use of corporate aircraft for personal travel as part of his employment agreement. However, the HR Committee has offset Mr. Morris' compensation opportunity by an amount approximating the incremental cost to the Company of his personal use of corporate aircraft above that of other CEOs in AEP' s Compensation Peer Group. Taxes are withheld on the value of executive personal use of corporate aircraft in accordance with IRS standards. AEP does not provide a gross-up for these taxes.

The Company occasionally allows spouses to accompany executives on trips using business aircraft if there is no incremental cost to the Company, such as when a spouse accompanies an executive on a business trip. Taxes are withheld on the value of executive spouse travel on corporate aircraft in accordance with IRS standards, and AEP does not provide a gross-up for these taxes.

AEP provides executives with independent financial counseling and tax preparation services to assist executives with financial planning and tax filings. Income is imputed to executives and taxes are withheld for financial counseling and tax preparation services. No tax gross-ups are provided.

Other Compensation Information

Recoupment of Incentive Compensation.

The Board believes that incentive compensation should be reimbursed to the Company if, in the Board' s determination:

Such incentive compensation was predicated upon the achievement of financial or other results that were subsequently materially restated or corrected, The officer from whom such reimbursement is sought engaged in misconduct that caused or partially caused the need for the restatement or correction, and

A lower payment would have been made to the executive based upon the restated or corrected financial results.

The Board adopted this policy in February 2007, and the HR Committee has directed the Company to design and administer all of the Company' s incentive compensation programs in a manner that provides for the Company' s ability to obtain such reimbursement. The Company will seek reimbursement, if and to the extent that, in the Board' s view, such reimbursement is warranted by the facts and circumstances of the particular case or if the applicable legal requirements impose more stringent requirements on AEP to obtain reimbursement of such compensation. AEP may also retain any deferred compensation previously credited to the executive if, when and to the extent that it otherwise would become payable. This right to reimbursement is in addition to, and not in substitution for, any and all other rights AEP might have to pursue reimbursement or such other remedies against an executive for misconduct in the course of employment by AEP or otherwise based on applicable legal considerations.

Role of the CEO with Respect to Determining Executive Compensation. The HR Committee has invited the CEO to attend all HR Committee meetings. The HR Committee regularly holds executive sessions without the CEO or other management present to provide a confidential avenue for any concerns to be expressed. The CEO, in his role as Chairman of the Board, has the authority to call a meeting of the HR Committee.

The CEO has assigned AEP' s Senior Vice President – Shared Services, Vice President – Human Resources and Director – Compensation and Executive Benefits to support the HR Committee. These individuals work closely with the HR Committee Chairman, the CEO and the Committee' s independent compensation consultant (Richard Meischeid of Pay Governance) to research and develop requested information, prepare meeting materials, implement the HR Committee' s actions and administer the Company' s executive compensation and benefit programs in keeping with the objectives established by the HR Committee. The management supporting the HR Committee also meets with the CEO, the HR Committee Chairman and Mr. Meischeid prior to meetings to review and finalize the meeting materials.

The CEO regularly discusses his strategic vision and direction for the Company during HR Committee meetings with Mr. Meischeid in attendance. Likewise, Mr. Meischeid regularly discusses compensation strategy alternatives, in light of the CEO' s strategic vision and direction, during HR Committee meetings with the CEO in attendance. The HR Committee believes that this open dialog and exchange of ideas is important to the development and implementation of a successful executive compensation strategy. The CEO did not retain any outside compensation consulting services or otherwise seek compensation advice regarding AEP' s executive compensation and benefits.

Mr. Morris discusses the individual performance of all the named executive officers with the HR Committee and recommends their compensation to the HR Committee. As CEO, he also has substantial input into the development of employment offers for outside candidates for executive positions, although all employment offers for executive officer positions require the approval of the HR Committee.

The CEO does not play any role in determining or recommending director compensation but he does generally attend meetings of the Directors and Corporate Governance Committee, which is responsible for developing a recommendation to the full Board as to the compensation of non-management directors. In 2010 the Directors and Corporate Governance Committee hired an outside compensation consultant (Meridian Compensation Partners, LLC), which is independent from both the Company and the HR Committee' s executive compensation consultant, to help it meet this responsibility. The Board of Directors makes the final determination on directors' compensation.

Change In Control Agreements. The HR Committee provides change in control agreements to all the named executive officers to help align the interests of these executives with those of AEP' s shareholders by mitigating the financial impact if their employment is terminated as a result of a change in control. The HR Committee also considers change in control agreements as an important tool in recruiting external candidates for certain executive positions. The HR Committee limits participation to those executives whose full support and sustained contributions in the course of a lengthy and stressful possible corporate transaction would be critical to the successful completion of a change in control. As of December 31, 2010 there were 17 executives who have change in control agreements.

While the HR Committee believes these agreements are consistent with the practices of its peer companies, the most important reason for these agreements is to protect the Company and the interests of shareholders in the event of an anticipated or actual change in control. During such transitions, retaining and continuing to motivate the Company' s key executives would be critical to protecting shareholder value. In a change of control situation, outside competitors are more likely to try to recruit top performers away from the Company, and our executive officers may consider other opportunities when faced with uncertainty about retaining their positions. Therefore, the HR Committee uses these agreements to provide security and protection to officers in such circumstances for the long-term benefit of the Company and its shareholders.

The Board has adopted a policy that requires shareholder approval of future executive severance agreements that provide benefits generally exceeding 2.99 times the sum of the named executive officer' s salary plus annual incentive compensation. In consultation with its independent executive compensation consultant, the HR Committee periodically reviews change in control agreement practices for similar companies, including the companies in our Compensation Peer Group. The HR Committee has found that change in control agreements are common among these companies, and that 2.99 is the most common multiple for executive officers. Therefore, the HR Committee approved change in control multiples of 2.99 times base salary and bonus for all of the named executive officers. Other executives covered by change in control agreements may have a lesser multiple of 2.0 times their base salary and target annual incentive award. All AEP change in control agreements have a "double trigger," which is a change in control accompanied by an involuntary termination or constructive termination within two years.

If the payments made to a named executive officer on account of his or her termination exceed certain amounts, the Company may not be able to deduct the payments for federal income tax purposes and the named executive officer could be subject to a 20% excise tax on such payments. The excise tax is in addition to the executive' s regular payroll and income taxes. Change in control agreements entered into prior to November 2009 offset the effect of the excise tax with a "gross-up" payment that reimburses executives for the excise tax. However, the total benefit that an executive would receive by reason of the change in control will be reduced by up to 5% if that reduction would avoid the excise tax. The gross-up payment to reimburse the executive for these excise taxes is no longer being included in change in control agreements entered into with new participants after October 2009.

In the event of a change in control, a pro-rata portion of outstanding performance units for performance periods beginning before 2011 would vest and would be paid at a target performance score. For performance periods beginning on or after January 1, 2011, a double trigger was added to performance unit awards. This double trigger requires the termination of a participant' s employment under defined circumstances within one year after a change in control in order for a pro-rata portion of their outstanding performance unit awards to vest and be paid at the target performance score.

All outstanding restricted stock unit awards granted effective before January 1, 2011 vest in the event of a change in control. A double trigger was also added to restricted stock unit awards granted effective on or after January 1, 2011. This double trigger requires that a participant’ s employment be terminated under defined circumstances within one year after a change in control in order for all of their outstanding restricted stock units to vest.

Other compensation and benefits provided to executive officers in the event their employment is terminated as a result of a change in control are consistent with that provided in the event a participant’ s employment is terminated due to a consolidation, restructuring or downsizing as described below.

Other Employment Separations. AEP maintains a severance plan that provides two weeks of base pay per year of service to all employees, including executive officers, if their employment is terminated due to a consolidation, restructuring or downsizing, subject to the employee’ s agreement to waive claims against AEP. Mr. Morris’ s employment agreement, however, provides him a severance payment equal to two times his annual base salary in the event of his severance. In addition, our severance benefits for all employees include outplacement services and access to health benefits at a reduced net cost for up to 18 months (or until age 65 for employees who are at least age 50 with 10 years of service at the time of their severance).

Named executive officers and other employees remain eligible for an annual incentive award based on their eligible pay for the year, which reflects the portion of the year that they worked, if they separate from service prior to year-end due to their retirement; severance attributed to restructuring, consolidation or downsizing; or death.

A prorated portion of outstanding performance units vest if a participant retires, which is defined as a termination other than for cause after the executive reaches age 55 with five years of service or if a participant is severed. Mr. Morris, Mr. English and Mr. Powers were retirement eligible in 2010. A prorated portion of outstanding performance units would also vest to a participant’ s heirs in the event of their death.

In 2010, executive officers are also entitled to one year of continued financial counseling service in the event they are severed from service as the result of a restructuring, consolidation or downsizing. In the event of their death, their spouse or the executor of their estate would be eligible for this benefit. For 2011, this benefit was reduced to 6 months of continued financial counseling service in the event of termination due to severance or death.

Insider Trading and Hedging.

The Company maintains an insider trading policy that prohibits directors and officers from directly hedging their AEP stock holdings through short sales and the use of options, warrants, puts and calls or similar instruments. The policy also prohibits directors and officers from placing AEP stock in margin accounts without the approval of the Company. The Company is unaware of any executive officer who has attempted to directly or indirectly hedge the economic risk associated with minimum stock ownership requirements. The Company is also not aware of any executive officer or director who has pledged or otherwise encumbered their shares of AEP stock.

Tax Considerations.

Section 162(m) of the Internal Revenue Code limits the Company’ s ability to deduct compensation in excess of $1,000,000 paid in any year to the Company’ s CEO or any of the next three highest paid named executive officers, other than the Chief Financial Officer. The HR Committee considers the limits imposed by Section 162(m) when designing compensation and benefit programs for the Company and its executive officers. Because the annual incentive compensation awarded in 2010 was performance based and awarded by a committee of independent outside directors pursuant to the Senior Officer Incentive Plan (the SOIP), which was approved by shareholders, its deductibility is not subject to the Section 162(m) limit. The HR Committee established 0.75% of income before discontinued operations, extraordinary items and the cumulative effect of accounting changes (Adjusted Income) as the performance measure for the 2010 SOIP and further allocated a specific percentage of Adjusted Income to each executive officer. In this way, the HR Committee retains the flexibility to make awards that are based on individual performance in a way that is consistent with the requirements for tax deductibility by the Company under section 162(m) of the Internal Revenue Code. In no case did the annual incentive awards paid for 2010 exceed the maximum award provided under the SOIP. Amounts paid to the named executive officers for vested performance units, which were granted under the shareholder approved Long-Term Incentive Plan, also are not subject to the deductibility limit because they are performance based.

AEP' s restricted shares and restricted stock units are not considered to be performance based under Section 162(m). Therefore, any amounts attributable to those restricted shares and units are not tax deductible if and to the extent that they cause the compensation of the covered executive officer to exceed $1,000,000 for the year.

By meeting the requirements for performance based compensation under Section 162(m) for annual incentive compensation and performance units, these payments are eligible for deduction. The HR Committee intends to continue to utilize shareholder approved plans and performance based awards to allow the Company to deduct most annual and long-term incentive compensation paid to named executive officers, while maintaining sufficient flexibility to award appropriate incentives to named executive officers.

In addition, Sections 280G and 4999 of the Internal Revenue Code limit income tax deductions for the Company and impose excise taxes on named executive officers who receive payments in excess of a defined limit upon a change in control. As discussed under "Potential Payments upon Termination or Change in Control of the Company" on page 63, certain payments to the named executive officers may be reduced to a limited extent to avoid the imposition of the excise tax, but payments to the named executive officers in connection with a change in control may be subject to these taxes (and loss of tax deductions).

Finally, Section 409A of the Internal Revenue Code imposes additional taxes on named executive officers whose deferred compensation fails to comply with Section 409A. The Company has reviewed its compensation arrangements to help ensure they comply with applicable Section 409A requirements.

Human Resources Committee Report

Membership and Independence. The HR Committee had five members in 2010. The Board has determined that each member of the HR Committee is an independent director, as defined by the New York Stock Exchange listing standards. Each member of the HR Committee attended professional development training in 2010 that addressed topics of specific relevance to public company compensation committees.

Purpose. The primary purpose of the HR Committee is to provide independent oversight of the compensation and human resources policies and practices of the Company. The primary objective of the HR Committee with respect to executive compensation is to ensure that executive officers and other key employees are compensated in a manner that is consistent with the Company' s business strategy, risk tolerance, competitive practices, internal equity considerations, and Company and Board policies.

Functions and Process. The HR Committee operates under a written charter reviewed, modified and adopted annually by the Board. This charter is available on AEP' s web-site at *www.AEP.com/investors/corporategovernance*.

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The HR Committee annually reviews AEP' s executive compensation in the context of the performance of management and the Company. The HR Committee reviews and approves the compensation for all officers at the senior vice president level and above and other key employees. With respect to the compensation of the CEO, the HR Committee is responsible for making compensation recommendations to the independent members of the Board, who review and approve the CEO' s compensation.

In carrying out its responsibilities, the HR Committee addressed many aspects of AEP' s human resource and executive compensation programs and practices in 2010, including:

- Establishing annual and long-term performance objectives for senior executives,
- Assessing the performance of the CEO, other senior executives and the Company relative to those established performance objectives,
- Conducting an evaluation of the CEO based on written comments from board members, senior AEP management, Mr. Morris' direct reports and the audit firm partner overseeing AEP' s external audit,
- Determining the mix of base salary, short-term incentives and long-term equity based compensation to be provided to executives,
- Reviewing the design of the Company' s long-term incentive program and changing the mix of long-term incentive awards to better meet the Company' s current needs,
- Reviewing an analysis of executive compensation for all senior executives, including the named executive officers,
- Reviewing and approving the base salaries, annual incentive awards and long-term incentive award opportunities for all senior executives,
- Reviewing and approving the major elements of the Company' s benefits and perquisites,
- Evaluating whether and how the design of the Company' s executive compensation programs and practices affect risk taking,
- Reviewing and approving the major terms of employment, change in control and any other special agreements with executives,

Reviewing the Company' s workforce safety efforts and results,

Reviewing the senior management succession plan, including succession candidates for the CEO position,

Reviewing and approving reports to shareholders regarding executive compensation, and

Selecting and engaging a compensation consultant to provide objective and independent advice to the HR Committee.

In establishing performance objectives, the HR Committee considers the interests of other major AEP stakeholders, such as AEP' s customers, employees, and the communities in which AEP operates, in addition to those of AEP' s shareholders. For example, the HR Committee tied 2010 annual incentive compensation for all executive officers to measures that included employee safety, while also tying funding for annual incentive compensation to AEP' s earnings per share.

In determining executive compensation, the HR Committee considers all relevant factors, including:

Company performance,

The CEO’ s individual performance, based, in part, on a leadership assessment that specifically covers integrity and ethics, communication, willingness to confront tough issues, business acumen, strategic planning, teamwork, fostering a high performance culture and leadership of the board of directors,

Individual performance and compensation recommendations for other executive officers as assessed by the CEO and their direct manager,

Market competitive compensation survey information from the executive compensation study conducted by the HR Committee’ s independent compensation consultant,

Succession planning,

The responsibilities and experience of each senior officer,

Compensation history,

The impact salary changes may have on other elements of total rewards,

The impact of compensation on risk taking,

The expense implications of any changes, and

Tally sheets, showing multiple views of each of the named executive officer’ s total compensation.

2011 Changes. During 2010 the HR Committee changed the mix of awards to be issued for 2011 and future years to executive officers and other AEP management under its regular annual long-term incentive program. It will provide 40% of the value in restricted stock units and 60% of the value in performance units, rather than 100% in performance units. This change was made to provide a stronger retention incentive and more market competitive compensation during both up and down cycles. This change also brings AEP’ s long-term incentive award mix closer to that of the companies in AEP’ s Compensation Peer Group. The restricted stock unit awards include a two year post retirement holding requirement for senior executives who are subject to mandatory retirement. This post retirement holding period was introduced to mitigate the risk created near the end of an executive’ s career when many long-term incentive awards lose some of their capacity to encourage decision making in the long-term interests of the Company.

In addition, the HR Committee changed the terms under which long-term incentive awards are granted effective for 2011 and future years to implement double trigger vesting in the event of a change in control of the Company. This double trigger requires that a participant' s employment be terminated under defined terms for special vesting to apply in the event of a change in control.

The HR Committee' s Independent Compensation Consultant. In January 2010 the HR Committee reengaged Towers Watson, with Richard Meischeid as its lead consultant, to provide recommendations to the HR Committee regarding AEP' s executive compensation and benefit programs and practices. Mr. Meischeid is a nationally recognized executive compensation consultant. Prior to May 2010 he was a Principal with Towers Watson. In May 2010 Mr. Meischeid left Towers Watson and became a Managing Partner at Pay Governance. The HR Committee then engaged Pay Governance, with Mr. Meischeid as its lead consultant, to provide it with executive compensation consulting services. The HR Committee is authorized to retain and terminate consultants and advisors without management approval, and has the sole authority to approve their fees. Among other assignments, the HR Committee' s consultant provides an annual executive compensation study and a report on current executive compensation and benefits trends within the electric utility industry and among U.S. industrial companies in general. In 2010, the Company paid $56,923 for executive compensation consulting services provided to the HR Committee by Towers Watson and $54,959 for such services provided by Pay Governance.

The HR Committee annually assesses and discusses the performance and independence of its executive compensation consultant. In January 2010 as part of this assessment and prior to

Mr. Meischeid leaving Towers Watson to form Pay Governance, the HR Committee considered the extent of other business that Towers Watson performed for AEP and reviewed the safeguards that were in place to ensure the independence of the advice they received. After reviewing the cost of the work Towers Watson performs for the HR Committee and other work performed for AEP, the HR Committee concluded that, although Towers Watson performed an extensive amount of other services for the Company, adequate barriers and safeguards were in place to ensure that Mr. Meischeid' s and Towers Watson' s executive compensation recommendations were not in any way influenced by this other business. Company management engaged Towers Watson to provide these other services, and during 2010 paid $1,244,785 for these services.

As of May 2010 any concern about other business creating the potential for a conflict of interest has been eliminated because Pay Governance has not performed and will not be hired to perform any work for AEP other than that which is related to their engagement by the HR Committee.

The Committee also annually reviews the performance and objectivity of its executive compensation consultant and found in all cases that the advice provided was of a high quality and appropriate for the Company. The HR Committee further concluded that Mr. Meischeid was not unduly influenced by AEP management and was providing objective and independent advice. Neither Pay Governance nor Towers Watson have or had any role in recommending director compensation. The HR Committee regularly holds executive sessions with Mr. Meischeid to help ensure that it receives full and independent advice.

In fulfilling its oversight responsibilities, the HR Committee reviewed and discussed with management the Compensation Discussion and Analysis set forth in this Proxy Statement. Based on its review and these discussions, the HR Committee recommended to the Board that the Compensation Discussion and Analysis be included in the Company' s Annual Report on Form 10-K for the fiscal year ended December 31, 2010 and in the Company' s proxy statement to be filed in connection with the Company' s 2011 Annual Meeting of Shareholders, each of which will be filed with the Securities and Exchange Commission.

Human Resources Committee Members

Donald M. Carlton
James F. Cordes
Ralph D. Crosby, Jr.
Thomas E. Hoaglin
Lester A. Hudson, Jr., Chair

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Executive Compensation

Summary Compensation Table

The following table provides summary information concerning compensation paid or accrued by us to or on behalf of our Chairman and Chief Executive Officer, our Executive Vice President and Chief Financial Officer and four other highly compensated executive officers, to whom we refer collectively as the named executive officers.

Name and Principal Position	Year	Salary ($)(1)	Bonus ($)	Stock Awards ($)(2)	Option Awards ($)	Non-Equity Incentive Plan Compen-sation ($)(3)	Change in Pension Value and Non-qualified Deferred Compen-sation Earnings ($)(4)	All Other Compen-sation ($)(5)	Total ($)
Michael G. Morris–	2010	1,270,442	–	5,321,150	–	1,579,785	341,768	512,969	9,026,114
Chairman of the board	2009	1,254,808	–	5,265,750	–	–	446,490	572,230	7,539,278
and chief executive officer	2008	1,259,615	–	5,955,000	–	1,654,071	330,564	818,438	10,017,688
Brian X. Tierney–	2010	467,365	–	2,703,635	–	425,000	180,228	29,456	3,805,684
Executive Vice President	2009	401,539	–	857,866	–	–	124,813	69,767	1,453,985
and Chief Financial Officer	2008	403,077	–	816,550	–	665,000	117,421	61,134	2,063,182
Robert P. Powers–	2010	523,844	–	2,763,712	–	420,961	511,871	34,569	4,254,957
President-AEP Utilities	2009	511,961	–	1,213,530	–	–	692,065	68,442	2,485,998
	2008	513,923	–	1,396,805	–	415,000	175,962	84,475	2,586,165
Nicholas K. Akins(6)–	2010	515,056	–	2,429,269	–	365,000	114,757	35,161	3,459,243

President	2009	451,731	–	857,866	–	–	129,664	61,652	1,500,913
	2008	440,961	–	915,164	–	340,000	54,428	58,093	1,808,646
Carl L. English–	2010	563,998	–	1,805,415	–	450,000	74,119	35,475	2,929,007
Vice Chairman	2009	552,115	–	1,848,128	–	–	108,781	74,965	2,583,989
	2008	554,231	–	2,136,178	–	450,000	88,541	69,837	3,298,787
Venita McCellon-Allen(7)–	2010	410,919	–	2,342,483	–	283,780	88,287	49,564	3,175,033
President & COO SWEPCo	2009	401,539	–	857,866	–	–	116,112	63,760	1,439,277
	2008	395,139	–	915,164	–	317,192	107,770	48,677	1,783,942

(1) Amounts in the salary column are composed of executive salaries and additional days of pay earned for years with more than the standard 260 calendar work days and holidays.

(2) The amounts reported in this column reflect the total grant date fair value, calculated in accordance with FASB ASC Topic 718, of performance units and restricted stock units granted under our Long-Term Incentive Plan. See Note 15 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2010 for a discussion of the relevant assumptions used in calculating these amounts. The value realized for the performance units, if any, will depend on the Company' s performance during a three-year performance and vesting period. The potential payout can range from 0% to 200% of the target number of performance units, including reinvested dividends, multiplied by the average closing price of AEP common stock for the last 20 trading days of the performance period. Therefore, the maximum amount payable is equal to 200% of the target award, plus an amount equal to any reinvested dividends on the performance units multiplied by the percentage increase in AEP' s share price from the grant or reinvestment date. For further information on these awards, see the Grants of Plan-Based Awards Table on page 50 and the Outstanding Equity Awards at Fiscal Year-End Table on page 54.

The 2010 amounts also include 41,380 restricted stock units awarded in August 2010 to Messrs. Akins, Powers and Tierney and Ms. McCellon-Allen. The maximum amount payable for the restricted stock units is equal to the award plus an amount equal to reinvested dividends multiplied by the percentage increase in AEP' s stock price from the grant or reinvestment date.

(3) The amounts shown in this column are annual incentive awards made under the Senior Officer Incentive Plan for the year shown. At the outset of each year, the HR Committee sets annual incentive targets and performance criteria that are used after year-end to determine if and the extent to which executive officers may receive annual incentive award payments under this plan.

(4)

The amounts shown in this column are attributable to the increase in the actuarial values of each of the named executive officer' s combined benefits under AEP' s qualified and non-qualified defined benefit plans determined using interest rate and mortality assumptions consistent with those used in the Company' s financial statements. See the Pension

Benefits Table on page 57, and related footnotes for additional information. No named executive officer received preferential or above-market earnings on deferred compensation. See Note 8 to the Consolidated Financial Statements included in our Form 10-K for the year ended December 31, 2010, for a discussion of the relevant assumptions.

(5) A detailed breakout of the amounts shown in the All Other Compensation column for 2010 is shown below. These amounts include Company contributions to the Company' s Retirement Savings Plan and the Company' s Supplemental Retirement Savings Plan.
For Mr. Morris, the amount shown for 2010 includes the aggregate incremental cost associated with his personal use of Company-provided aircraft of $444,737. This amount is the incremental cost to the Company for his personal use of Company-provided aircraft, including all operating costs such as fuel, a maintenance reserve for the hours flown, on-board catering, landing/ramp fees and other miscellaneous variable costs. Fixed costs that do not change based on usage, such as pilot salaries, the lease costs for Company aircraft and the cost of maintenance not related to personal trips, are excluded. For proxy reporting purposes, personal use of corporate aircraft includes the incremental cost of relocating aircraft to accommodate personal trips and the incremental costs of flights for Mr. Morris to attend outside board meetings for the public companies at which he serves as an outside director. In 2009, the HR Committee generally eliminated personal use of Company provided aircraft to the extent that such use has an incremental cost to the Company, except for Mr. Morris who negotiated this as part of his employment agreement.

(6) Mr. Akins was appointed President of the Company effective January 1, 2011. He was previously Executive Vice President−Generation.

(7) Ms. McCellon-Allen was Executive Vice President of AEP through June 30, 2010. In a corporate realignment, she became President and Chief Operating Officer of Southwestern Electric Power Company, one of AEP' s public utility subsidiaries. She currently is not an executive officer of AEP.

All Other Compensation for 2010

Type	Michael G. Morris	Brian X. Tierney	Robert P. Powers	Nicholas K. Akins	Carl L. English	Venita McCellon-Allen
Retirement Savings Plan Match	$ 4,327	$7,590	$ 10,727	$ 7,678	$11,025	$ 10,628
Supplemental Retirement Savings Plan Match	52,614	13,316	12,748	15,367	14,250	7,787
Director Life and Accident Insurance	741	–	–	–	–	–
Financial Counseling and Tax Preparation	10,550	8,550	11,094	12,116	9,800	11,149
Personal Use of Company Aircraft	444,737	–	–	–	–	–
Health & Wellness Program Incentives	–	–	–	–	400	–
Relocation Payment	–	–	–	–	–	20,000

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Grants of Plan Based Awards in 2010

The following table provides information on plan based awards granted in 2010 to each of our named executive officers.

Name	Grant Date Approval(1)	Grant Date	Estimated Possible Payouts Under Non-Equity Incentive Plan Awards(2) Threshold ($)	Target ($)	Maximum (3) ($)	Estimated Future Payouts Under Equity Incentive Plan Awards(4) Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (#)	Grant Date Fair Value of Stock and Option Awards(5) ($)
Michael G. Morris										
2010 Senior Officer Incentive Plan			–	1,391,881	2,783,762					
2010 – 2012 Performance Units	12/8/09	1/1/2010				19,375	155,000	310,000		5,321,150
Brian X. Tierney										
2010 Senior Officer Incentive Plan			–	348,433	696,866					
2010 – 2012 Performance Units	12/8/09	1/1/2010				4,383	35,060	70,120		1,203,610
Restricted Stock Units		8/3/2010							41,380	1,500,025
Robert P. Powers										
2010 Senior Officer Incentive Plan			–	365,164	730,328					
2010 – 2012 Performance Units	12/8/09	1/1/2010				4,601	36,810	73,620		1,263,687
Restricted Stock Units		8/3/2010							41,380	1,500,025
Nicholas K. Akins										

2010 Senior Officer Incentive Plan			–	332,879	665,758					
2010 – 2012 Performance Units	12/8/09	1/1/ 2010				3,286	26,290	52,580		902,536
2010 – 2012 Performance Units(6)	1/26/2010	1/26/ 2010				94	750	1,500		26,708
Restricted Stock Units		8/3/ 2010							41,380	1,500,025
Carl L. English										
2010 Senior Officer Incentive Plan			–	421,247	842,495					
2010 – 2012 Performance Units	12/8/09	1/1/ 2010				6,574	52,590	105,180		1,805,415
Venita McCellon-Allen										
2010 Senior Officer Incentive Plan			–	265,985	531,970					
2010 – 2012 Performance Units	12/8/09	1/1/ 2010				3,068	24,540	49,080		842,458
Restricted Stock Units		8/3/ 2010							41,380	1,500,025

(1) On December 8, 2009, the HR Committee and the independent members of the board approved performance unit awards, effective January 1, 2010, under AEP' s long-term incentive plan. The performance and vesting period for these awards is January 1, 2010 through December 31, 2012.

(2) Consists of potential payouts under the Senior Officer Incentive Plan, which are based on base salary paid during the year.

(3) The amount shown in this column represents 200% of the target award for each of the named executive officers, which is generally the maximum annual incentive award for all AEP executives and other employees. 2010 awards under the SOIP were also capped in aggregate at 0.75% of income before discontinued operations, extraordinary items and the cumulative effect of accounting changes. In addition, the maximum award payment to any SOIP participant for any year is the lesser of:

(i) $6,000,000 or

(ii) 400% of the executive' s base salary (prior to any salary reduction or deferral elections) as of the date of grant of the award.

(4) Consists of performance units awarded under our Long-Term Incentive Plan for the three-year performance period 2010 – 2012. These awards, if any, generally vest at the end of the three year performance period. For further information on these awards, see the description under 2010 Stock Award Grants below.

(5) For performance units, the value is computed by multiplying the closing price of AEP common stock on December 8, 2009 ($34.33) by the target number of performance units granted. The actual number of performance units earned will depend on AEP' s performance over the 2010 through 2012 period and could vary from zero percent (0%) to two-hundred percent (200%) of the target award plus reinvested dividends. The value of performance units earned will be equal to AEP' s average closing share price for the last 20 trading days of the performance period multiplied by the number of performance units earned. For restricted stock units, the value is computed by multiplying the closing price of AEP common stock on August 3, 2010 ($36.25) by the number of restricted stock units (41,380).

(6) 750 performance units approved by the HR Committee on January 26, 2010 when the closing price of AEP common stock was $35.61 as a result of a promotion.

Narrative Disclosure to Summary Compensation Table and Grants of Plan Based Awards Table

2010 Stock Award Grants. The named executive officers were awarded performance units effective January 1, 2010. These performance units were granted for a three-year performance period (2010-2012) and generally vest, subject to the participant' s continued employment, at the end of the performance period. Performance units are generally equivalent in value to shares of AEP common stock. Dividends are reinvested in additional performance units. The 2010-2012 performance units are subject to two equally weighted performance measures for the three-year performance period, which are:

Three-year total shareholder return relative to the electric utility and multi-utility companies included in the S&P 500 Index, and

Three-year cumulative earnings per share relative to a performance measure established by the HR Committee.

These performance measures are described in detail in Compensation Discussion and Analysis-Performance Units on page 37. The scores for these performance measures determine the percentage of the performance units earned at the end of the performance period and can range from zero percent to 200 percent of the target. The value of each performance unit that is earned equals the average closing price of AEP common stock for the last twenty trading days of the performance period.

2010 Restricted Stock Unit Grants. Messrs. Akins, Powers and Tierney and Ms. McCellon-Allen were granted 41,380 restricted stock units in August 2010. These executives were four internal candidates considered as likely successors to AEP' s CEO position. These restricted stock units will generally vest, subject to the executive' s continued employment, in equal installments on August 3, 2013, August 3, 2014 and August 3, 2015, respectively. Dividends are reinvested in additional restricted stock units.

2011 Stock Award Grants. Effective January 1, 2011, the named executive officers were granted long-term incentive awards as part of AEP' s regular annual grant cycle. Of these awards, 60 percent was granted in the form of performance units for the 2011-2013 three-year performance period. They were issued under terms that are otherwise similar to those described above for the 2010-2012 performance period. The three-year cumulative earnings per share target for the 2011-2013 is $9.70. The relative total shareholder return performance measure for these performance units is identical to that for the previously granted performance units. The remaining 40 percent of these long-term incentive awards was granted in the form of restricted stock units that generally vest, subject to the executive officer' s continued employment, in three equal installments on May 1, 2012, May 1, 2013 and May 1, 2014. In addition, both the 2011 performance unit and restricted stock unit awards were granted with change in control provisions that include a double trigger that only provides earlier vesting of awards in the event of a change in control and a separation from service. The restricted stock unit awards granted for 2011 also include a two year post retirement holding requirement for senior executives who are subject to mandatory retirement.

2010 Non-Equity Incentive Compensation. For 2010 the HR Committee established the following annual incentive targets for the named executive officers:

110 percent of base salary for Mr. Morris,

75 percent of base salary for Mr. English and Mr. Tierney,

70 percent of base salary for Mr. Powers, and

65 percent of base salary for Mr. Akins and Ms. McCellon-Allen.

Actual awards generally may vary from 0% to 200% of the annual incentive target.

The HR Committee set target funding for the 2010 annual incentive compensation program at $3.00 per share, the midpoint of the Company' s publicly disclosed ongoing earnings guidance of $2.80 to $3.20 per share.

In 2010 AEP produced ongoing EPS of $3.03, which was above the midpoint of AEP' s earnings guidance for the year, which resulted in a score of 113.5% of target. For 2010, ongoing EPS was $0.53 more than earnings per share reported in AEP' s financial statements related to (1) the Company' s restructuring program, (2) the disallowance in Virginia of the recovery of the Company' s carbon capture and storage project, and (3) the unfavorable tax treatment of a Medicare subsidy. See our Form 8-K filed on January 28, 2011 announcing 2010 fourth quarter and year-end earnings for a reconciliation of ongoing and reported EPS.

For 2010 the HR Committee again used an executive council scorecard with four performance categories: safety, operating performance, regulatory performance and strategic initiatives. For 2010, the HR Committee again established a fatality deduction that would have reduced the overall score for all executive officers by 25% of target if AEP had experienced an accidental work related employee fatality. Due to AEP' s 2010 reorganization, it was determined that the executive council scorecard would be used for all incentive groups for 2010 and that all groups would receive the same score. As a result, the Overall Performance Score for 2010 for all groups, including AEP' s Executive Officers, is the EPS score of 113.5% of target.

Based on this EPS score, a 2010 award pool of 113.5% of target was provided for each incentive group, including the Executive Officers. The HR Committee then allocated annual incentive awards from this funding pool to the Executive Officers, other than the CEO, based on a subjective assessment of each executive' s performance. The independent members of the Board also determined the annual incentive award for the CEO based on a subjective assessment of his performance. The 2010 annual incentive awards are shown in the Non-Equity Incentive Plan Compensation column of the Summary Compensation Table and reflect adjustments above and below 113.5% of target based on these assessments of individual performance.

AEP provides annual incentive compensation to executive officers through the Senior Officer Incentive Plan, which was approved by shareholders at the 2007 annual meeting. This plan establishes the maximum annual incentive award opportunity for each executive officer. For further information, see Tax Considerations on page 43.

Employment Agreements. The Company entered into an employment agreement (Agreement) with Mr. Morris that became effective January 1, 2004 for a three-year period. The Agreement is automatically renewed for additional one-year periods unless Mr. Morris or the Company takes specific action to terminate it. Under the agreement, Mr. Morris is eligible to receive an annual bonus under the Senior Officer Incentive Plan based on a target percentage of at least 100% of his base salary.

The Agreement awarded Mr. Morris a nonqualified stock option grant of 149,000 shares and 200,000 restricted shares, payable in three installments, as a replacement for certain long-term compensation that he forfeited from his prior employer in order to accept employment with the Company. The first component of 66,666 shares vested on November 30, 2009, and the next component of 66,667 shares vested on November 30, 2010. The remaining 66,667 restricted shares will vest, subject to his continued employment, on November 30, 2011.

The Agreement provides that Mr. Morris may use the Company aircraft for personal use in accordance with Company policies in effect for senior executives. Mr. Morris is entitled to participate in the Company' s financial counseling program.

The Company purchased a life insurance policy for Mr. Morris with a $3 million death benefit, and paid annual premiums for five years through 2008 to maintain that policy. Mr. Morris was provided an opening balance in the AEP Supplemental Benefit Plan of $2.1 million. Mr. Morris vested in this plan in 20% increments on each of the first five anniversary dates of his employment. Mr. Morris is credited with the maximum rate permitted under the AEP Note (2) under Supplemental Benefit Plan (currently at 8.5%) on all eligible earnings. For further information, see Pension Benefits on page 57. If the Company terminates the Agreement for reasons other than cause, Mr. Morris will receive a severance payment equal to two times his annual base salary.

The Company entered into an employment agreement with Mr. English (English Agreement) that became effective August 2, 2004. Mr. English is eligible to receive an annual bonus under the Senior Officer Incentive Plan, and his target percentage will be equal to at least 65% of his base salary. The English Agreement awarded Mr. English 30,000 restricted stock units, which vested in equal thirds in August 2005, 2006 and 2007. Mr. English' s cash balance account under the AEP Supplemental Benefit Plan is credited with the maximum rate permitted (currently at 8.5%) on all eligible earnings. For further information, see Note (2) under Pension Benefits on page 57.

Mr. Powers and Ms. McCellon-Allen each have agreements with the Company, which result in their being credited with 17 and 4.2 years, respectively, of additional service under AEP' s Supplemental Benefit Plan. For further information on these agreements, see Notes (3) and (4) under the Pension Benefits on page 57.

In addition to these agreements, each of the named executive officers has entered into a Change In Control Agreement with AEP. For further information about these Change In Control Agreements see Potential Payments upon Termination or Change in Control on page 63.

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Outstanding Equity Awards at Fiscal Year-End for 2010

The following table provides information with respect to holdings of stock options, restricted stock, restricted stock units and performance unit awards by the named executive officers at December 31, 2010.

	Option Awards			Stock Awards			
Name	Number of Securities Underlying Unexercised Options (#) Exercisable	Option Exercise Price ($)	Option Expiration Date	Number of Shares or Units of Stock That Have Not Vested (#)	Market Value of Shares or Units of Stock That Have Not Vested ($)	Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
Michael G. Morris							
Stock Options	149,000	30.76	1/2/ 2014				
Restricted Shares(1)				66,667	2,398,679		
2009 - 2011 Performance Units(2)						194,475	6,997,211
2010 - 2012 Performance Units(2)						162,773	5,856,573
2011 - 2013 Performance Units(2)						90,000	3,238,200
Restricted Stock Units(5)				60,000	2,158,800		
Brian X. Tierney							
2009 - 2011 Performance Units(2)						31,683	1,139,954
2010 - 2012 Performance Units(2)						36,818	1,324,712
2011 - 2013 Performance Units(2)						20,328	731,401

Restricted Stock Units(4)	42,395	1,525,372		
Restricted Stock Units(5)	13,552	487,601		
Robert P. Powers				
2009 - 2011 Performance Units(2)			44,818	1,612,552
2010 - 2012 Performance Units(2)			38,656	1,390,843
2011 - 2013 Performance Units(2)			19,026	684,555
Restricted Stock Units(4)	42,395	1,525,372		
Restricted Stock Units(5)	12,684	456,370		
Nicholas K. Akins				
2009 - 2011 Performance Units(2)			31,683	1,139,954
2010 - 2012 Performance Units(2)			28,396	1,021,688
2011 - 2013 Performance Units(2)			19,026	684,555
Restricted Stock Units(4)	42,395	1,525,372		
Restricted Stock Units(5)	12,684	456,370		
Carl L. English				
2009 - 2011 Performance Units(2)			68,255	2,455,815
2010 - 2012 Performance Units(2)			55,227	1,987,067

2011 - 2013 Performance Units(2)			25,410	914,252
Restricted Stock Units(5)	16,940	609,501		

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Name	Option Awards: Number of Securities Underlying Unexercised Options (#) Exercisable	Option Awards: Option Exercise Price ($)	Option Awards: Option Expiration Date	Stock Awards: Number of Shares or Units of Stock That Have Not Vested (#)	Stock Awards: Market Value of Shares or Units of Stock That Have Not Vested ($)	Stock Awards: Equity Incentive Plan Awards: Number of Unearned Shares, Units or Other Rights That Have Not Vested (#)	Stock Awards: Equity Incentive Plan Awards: Market or Payout Value of Unearned Shares, Units or Other Rights That Have Not Vested ($)(3)
Venita McCellon-Allen							
2009 – 2011 Performance Units(2)						31,683	1,139,954
2010 – 2012 Performance Units(2)						25,771	927,241
2011 – 2013 Performance Units(2)						13,062	469,971
Restricted Stock Units(4)				42,395	1,525,372		
Restricted Stock Units(5)				8,708	313,314		

(1) Mr. Morris has 66,667 remaining restricted shares that he received upon his hire. They will vest, subject to his continued employment, on November 30, 2011. He receives dividends on these restricted shares.

(2) AEP currently grants performance units at the beginning of each year with a three-year performance and vesting period. This results in awards for overlapping successive three-year performance periods. These awards generally vest at the end of the three year performance period. The performance unit awards for the 2008 – 2010 performance period vested at year-end and are shown in the Options Exercises and Stock Vested table below. The awards for the 2011 – 2013 performance period were approved by the HR Committee on December 7, 2010, effective January 1, 2011. The awards shown for the 2009 – 2011 and 2010 – 2012 performance periods include performance units resulting from reinvested dividends.

(3) The market value of the performance units reported in this column was computed by multiplying the closing price of AEP’ s common stock on December 31, 2010 ($35.98) by the target number of performance units including performance units resulting from reinvested dividends. The actual number of performance units issued upon vesting will be based on AEP’ s performance over the applicable three year period.

(4) These restricted stock units were granted on August 3, 2010, and includes restricted stock units resulting from reinvested dividends. These units will vest, subject to the executive officer’ s continued employment, in three equal installments, on August 3, 2013, August 3, 2014 and August 3, 2015, respectively.

(5) These restricted stock units were approved by the HR Committee on December 7, 2010, effective January 1, 2011. They will vest, subject to the executive officer' s continued employment, in three equal installments, on May 1, 2012, May 1, 2013 and May 1, 2014, respectively.

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Option Exercises and Stock Vested for 2010

The following table provides information with respect to the vesting of stock options, restricted shares and performance units granted to our named executive officers.

	Option Awards		Stock Awards	
Name	Number of Shares Acquired on Exercise (#)	Value Realized on Exercise ($)	Number of Shares Acquired on Vesting (#)(1)	Value Realized on Vesting ($) (2)
Michael G. Morris	–	–	147,651	5,287,150
Brian X. Tierney	–	–	11,105	399,558
Robert P. Powers	46,001	335,694	18,996	683,476
Nicholas K. Akins	5,900	52,960	12,446	447,807
Carl L. English	–	–	29,051	1,045,255
Venita McCellon-Allen	–	–	12,446	447,807

(1) Represents performance units under the Company' s Long-Term Incentive Plan for the 2008 - 2010 performance period that vested on December 31, 2010. For Mr. Morris, this column also includes 66,667 restricted shares that vested on November 30, 2010.

(2) As is required, the value shown in this column for the performance units is computed by multiplying the number of units by the market value of these units on the vesting date ($35.98). However, the actual value realized from these units was based on the previous 20-day average closing market price of AEP common stock as of the vesting date ($35.837). For Mr. Morris, this column also includes 66,667 restricted shares that vested on November 30, 2010 with a market value on the vesting date of $35.60 per share. For a more detailed discussion of vesting of the performance units, see the Long-Term Incentive Compensation section of the Compensation Discussion and Analysis beginning on page 37.

Executive officers may only exercise stock options pursuant to AEP' s Insider Trading Policy. In addition, an attorney from AEP' s legal department must approve in advance each sale of AEP stock by an executive officer.

In December 2007 the HR Committee granted performance units for a 2008 through 2010 performance period and established two equally weighted performance measures for this performance period:

Total Shareholder Return measured relative to the utility companies in the S&P 500 Index, and

Cumulative earnings per share measured relative to a target approved by the HR Committee.

The threshold, target and maximum payout levels are shown in the table below.

AEP' s total shareholder return for this performance period was at the 43.3 percentile of the utility companies in the S&P 500, which produced a score of 77.7%. AEP' s cumulative earnings per share was $9.23 for this performance period, compared to the target of $10.13. This produced an earnings per share score of 34.0%. The average of these two scores produced a composite score of 55.8% of the target award. These performance units vested on December 31, 2010 and were valued at the average closing price of AEP common stock for the last 20 days of the performance period, which was $35.837. The final score calculation for these performance measures is shown in the chart below.

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2008 – 2010 Performance Units

Performance Measures	Threshold Performance	Target Performance	Maximum Payout Performance	Actual Performance	Score	Weight	Weighted Score
3-Year Cumulative Earnings Per Share	$9.11 (25% payout)	$10.13 (100% Payout)	$11.14 (200% Payout)	$9.23	34.0%	50%	17.0%
3-Year Total Shareholder Return vs. S&P Electric Utilities	20th Percentile (0% Payout)	50th Percentile (100% Payout)	80th Percentile (200% Payout)	43.3 Percentile	77.7%	50%	38.8%
Composite Result							**55.8%**

Pension Benefits for 2010

The following table provides information regarding the pension benefits for our named executive officers under AEP' s pension plans. The material terms of the plans are described following the table.

Name	Plan Name	Number of Years Credited Service	Present Value of Accumulated Benefits(1)	Payments During Last Fiscal Year
Michael G. Morris				
	AEP Retirement Plan	7	$127,313	–
	AEP Supplemental Benefit Plan	7 (2)	$4,229,010	–
Brian X. Tierney				
	AEP Retirement Plan	12.7	$177,747	–
	AEP Supplemental Benefit Plan	12.7	$585,032	–
Robert P. Powers				
	AEP Retirement Plan	12.5	$395,264	–
	AEP Supplemental Benefit Plan	29.5 (3)	$2,987,301	–
Nicholas K Akins				
	AEP Retirement Plan	28.6	$376,590	–
	CSW Executive Retirement Plan	28.6	$239,483	–
Carl L. English				
	AEP Retirement Plan	6.5	$126,348	–
	AEP Supplemental Benefit Plan	6.5 (2)	$395,130	–

Venita McCellon-Allen				
	AEP Retirement Plan	18.8	$347,859 (5)	−
	AEP Supplemental Benefit Plan	27.3 (4)	$252,940	−
	CSW Executive Retirement Plan	16.8	$69,549 (6)	−

(1) The Present Value of Accumulated Benefits is based on the benefit accrued under the applicable plan through December 31, 2010, and the following assumptions (which are consistent with those used in AEP' s financial statements):

The named executive officer retires at age 65 (or, for Mr. Tierney and Mr. Powers retires at age 62, when unreduced benefits would be payable), and commences the payment of benefits (the "accrued benefit").

The value of the annuity benefit at the named executive officer' s assumed retirement age is determined based upon the accrued benefit, an assumed interest rate of 5.05%, 4.95% and 4.95% for the benefits accrued under the AEP Retirement Plan, AEP Supplemental Benefit Plan and the CSW Executive Retirement Plan, respectively, and assumed mortality based upon the IRS 2011 sex-distinct mortality tables. The value of the lump sum benefit at that assumed retirement age is determined based upon the accrued benefit, an assumed interest rate of 6.25% and assumed mortality based on the 2011 IRS Applicable Mortality table; and for Ms. McCellon-Allen' s lump sum benefit under the AEP Retirement Plan that is attributable to her participation in the CSW Retirement Plan (see note (5), below), an assumed 3% annual cost-of-living adjustment from her assumed retirement age. The present value of both the annuity benefit and the lump sum benefit at each executive’ s current age is based upon an assumed interest rate of 5.05%, 4.95% and 4.95% for the benefits accrued under the AEP Retirement Plan, AEP Supplemental Benefit Plan and CSW Executive Retirement Plan, respectively.

The present value of the accrued benefit is weighted based on 75% lump sum and 25% annuity (or 40% lump sum and 60% annuity for Mr. Powers due to his eligibility for early retirement under the final average pay benefit formula), based on the assumption that participants elect those benefit options in that proportion.

(2) Mr. Morris and Mr. English each has an individual agreement that provides for annual credits at the maximum rate provided (currently 8.5%). If not for their agreements, their combined age and service would have entitled each of them to an annual credit at 7.0% of eligible pay for each year prior to 2010 rather than the 8.5% maximum rate. Mr. Morris’ agreement further provides him an opening cash balance credit of $2,100,000 as of January 1, 2004. The higher crediting rate for Mr. Morris and Mr. English for years prior to 2010, and Mr. Morris’ opening cash balance credit, have augmented the present value of their accumulated benefits under the AEP Supplemental Benefit Plan as of December 31, 2010 by $3,187,154 and $87,340, respectively.

(3) Mr. Powers has an agreement with AEP that credits him with 17 years of service in addition to his actual years of service with AEP. His additional years of service credit have augmented the present value of his accumulated benefits under the AEP Supplemental Benefit Plan by $1,767,796.

(4) Ms. McCellon-Allen has an agreement with AEP that credits her with years of service based upon her original hire date of September 8, 1983, even though she was not employed with the company from July 1, 2000 until September 13, 2004. These 4.2 additional years of service credit have augmented the present value of her accumulated benefits under the AEP Supplemental Benefit Plan by $27,518.

(5) The benefit available to Ms. McCellon-Allen from the AEP Retirement Plan consists of two pieces: one under the cash balance formula since her return on September 13, 2004 (about 6.3 years of credited service), and one under the Central and South West Corporation Cash Balance Retirement Plan (the “CSW Retirement Plan”) for the period between January 1, 1985 and July 1, 2000 (her “CSW Retirement Plan Benefit”). Her CSW Retirement Plan Benefit will be paid to her either as a lump sum or in one of the annuity options offered by the plan. The amount available to her as a lump sum would be the greater of (i) her CSW Retirement Plan cash balance account ($126,402 as of December 31, 2010, adjusted for interest through her retirement) or (ii) the lump sum value of her CSW Retirement Plan protected minimum normal retirement annuity (which had accrued during the 12.5 year period until her traditional pension formula benefit became frozen effective July 1, 1997), calculated using a factor based on then applicable interest and mortality assumptions as well as an assumed future cost of living adjustment rate of 3.00%. The payments available to her in one of the plan’ s annuity options would be the greater of (i) her CSW Retirement Plan protected minimum normal retirement annuity ($3,497) or (ii) the life annuity equivalent of her then CSW Retirement Plan cash balance account, calculated using a factor based on then applicable interest and mortality assumptions.

(6) Ms. McCellon-Allen’ s benefit in the CSW Executive Retirement Plan is limited to that accrued during the period she participated in the plan (between September 8, 1983 and July 1, 2000).

Overview. AEP maintains tax-qualified and nonqualified defined benefit pension plans for eligible employees. The nonqualified plans provide (i) benefits that cannot be paid under the respective tax-qualified plans because of maximum limitations imposed on such plans by the Internal Revenue Code and (ii) benefits pursuant to individual agreements with certain of the named executive officers. The plans are designed to provide a source of income upon retirement to executives and their spouses, as well as a market competitive benefit opportunity as part of a market competitive total rewards package.

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AEP Retirement Plan. The AEP Retirement Plan is a tax-qualified defined benefit pension plan under which benefits are generally determined by reference to a cash balance formula. As of December 31, 2010, each of the named executive officers was vested.

In addition, employees who have continuously participated in the AEP Retirement Plan since December 31, 2000 ("Grandfathered AEP Participants," which includes Mr. Tierney and Mr. Powers) remain eligible for an alternate pension benefit calculated by reference to a final average pay formula. The benefits under this final average pay formula were frozen as of December 31, 2010.

The AEP Retirement Plan also encompasses the Central and South West Corporation Cash Balance Retirement Plan (the "CSW Retirement Plan"), which was merged into the AEP Retirement Plan effective December 31, 2008.

Cash Balance Formula. Under the cash balance formula, each participant has an account established to which dollar credits are allocated each year.

1. *Company Credits.* Each year, participant' s accounts are credited with an amount equal to a percentage of their salary for that year and annual incentive award for the prior year. The applicable percentage is based on the participant' s age and years of service. The following table shows the applicable percentage:

Sum of Age Plus Years of Service	Applicable Percentage
Less than 30	3.0 %
30-39	3.5 %
40-49	4.5 %
50-59	5.5 %
60-69	7.0 %
70 or more	8.5 %

Each year, the IRS calculates a limit on the amount of eligible pay that can be used to calculate pension benefits in a qualified plan. For 2010, the limit was $245,000.

2. *Interest Credits.* All amounts in the cash balance accounts earn interest at the average interest rate on 30-year Treasury securities for the month of November of the prior year. For 2010, the interest rate was 4.31%.

Final Average Pay Formula. Grandfathered AEP Participants receive their benefits under the cash balance formula or the final average pay formula, whichever provides the higher benefit. On December 31, 2010, the final average pay benefit payable at the Grandfathered AEP Participant' s normal retirement age was frozen, meaning that their final average pay formula benefit will no longer be affected by the participant' s subsequent service or compensation. Therefore, the final average pay normal retirement benefit for each of the Grandfathered AEP Participants was frozen as of December 31, 2010, based upon the participant' s then years of service times the sum of (i) 1.1% of the participant’ s then high 36 consecutive months of base pay (“High 36”); plus (ii) 0.5% of the amount by which the participant’ s then High 36 exceeded the participant’ s applicable average Social Security covered compensation.

AEP Supplemental Benefit Plan. The AEP Supplemental Benefit Plan is a nonqualified defined benefit pension plan. It generally provides eligible participants with benefits that are in excess of those provided under the AEP Retirement Plan (without regard to the provisions now included as the result of the merger of the CSW Retirement Plan into the AEP Retirement Plan) as determined upon the participant’ s termination of employment. These excess benefits are calculated under the terms of the AEP Retirement Plan described above with the following modifications: (i) additional years of service or benefit credits are taken into account; (ii) annual incentive pay was taken into account for purposes of the frozen final average pay formula; and (iii) the limitations imposed by the Internal Revenue Code on annual compensation and annual benefits are disregarded. However, eligible pay taken into account under the cash balance formula is limited to the greater of $1 million or two times the participant' s year-end base pay.

AEP previously granted certain named executive officers additional years of credited service, an opening balance credit, special crediting rates and special vesting schedules under the AEP Supplemental Benefit Plan. These special items are further described under Employment Agreements on page 52.

As of December 31, 2010, each of the named executive officers was fully vested in their AEP Supplemental Benefit Plan benefit.

CSW Executive Retirement Plan. The CSW Executive Retirement Plan is a nonqualified defined benefit pension plan. It generally provides eligible participants with benefits that are in excess of those provided under the terms of the former CSW Retirement Plan (which was merged into the AEP Retirement Plan) as determined upon the participant' s termination of employment. The excess benefits are calculated without regard to the limitations imposed by the Internal Revenue Code on annual compensation and annual benefits.

Nonqualified Deferred Compensation for 2010

The following table provides information regarding contributions, earnings and balances for our named executive officers under AEP' s three non-qualified deferred compensation plans which are each further described below.

Name	Plan Name(1)	Executive Contributions in Last FY(2) ($)	Registrant Contributions in Last FY(3) ($)	Aggregate Earnings in Last FY(4) ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE(5) ($)
Michael G. Morris						
	SRSP	236,569	52,614	364,882	–	3,088,898
	SORP	–	–	497,922	–	6,776,935
Brian X. Tierney						
	SRSP	29,958	13,316	110,204	–	1,202,913
	SORP	–	–	38,600		525,368
Robert P. Powers						
	SRSP	20,016	12,748	134,728	–	1,717,106
	ICDP	–	–	56,693	–	582,006
	SORP	–	–	111,084	–	1,485,071
Nicholas K. Akins						
	SRSP	34,712	15,367	19,379	–	381,611
	ICDP	–	–	18,752	–	174,946
	SORP	240,186	–	72,365	–	1,115,020
Carl L. English						
	SRSP	19,000	14,250	21,414	–	481,995
	SORP	–	–	171,189		2,329,953

Venita McCellon-Allen						
	SRSP	12,144	7,787	13,995	–	308,266
	SORP	–	–	90,163	–	1,227,159

(1) "SRSP" is the American Electric Power System Supplemental Retirement Savings Plan. "ICDP" is the American Electric Power System Incentive Compensation Deferral Plan. "SORP" is the American Electric Power System Stock Ownership Requirement Plan.

(2) The amounts set forth under "Executive Contributions in Last FY" are also reported in the Summary Compensation Table at either (i) Salary for 2010; (ii) the Non-Equity Incentive Plan Compensation column for 2009; or (iii) under Stock Awards column for 2008.

(3) The amounts set forth under "Registrant Contributions in Last FY" for the Supplemental Retirement Savings Plan are also reported in the Other Compensation column of the Summary Compensation Table.

(4) No amounts set forth under "Aggregate Earnings in Last FY" have been reported in the Summary Compensation Table as there were no above market or preferential earnings credited to any named executive officer' s account in any of the plans.

(5) The amounts set forth under "Aggregate Balance at Last FYE" include amounts reported in the Summary Compensation Table in previous years, and previous year earnings on such amounts, in addition to the current year contributions and earnings amounts shown in this table. The values shown for the SORP are calculated using the average closing price of AEP common stock for the 20 trading days up to and including the date shown, which is the methodology used to calculate distributions under this plan.

Overview. AEP maintains non-qualified deferred compensation plans that allow eligible employees, including the named executive officers, to defer receipt of a portion of their base salary, annual incentive and performance unit awards. The plans are unfunded. Participants have an unsecured contractual commitment from the Company to pay the amounts due under the plans from the general assets of the Company. AEP maintains the following plans:

The American Electric Power System Supplemental Retirement Savings Plan,

The American Electric Power System Incentive Compensation Deferral Plan, and

The American Electric Power System Stock Ownership Requirement Plan.

Supplemental Retirement Savings Plan. This plan allows eligible participants to save on a pre-tax basis and to continue to receive Company matching contributions beyond the limits imposed by the Internal Revenue Code on qualified plans of this type.

For 2010, participants could defer up to 20% of their base pay and annual incentive pay, up to $2,000,000. For subsequent years, participants can defer up to 50% of their base pay and annual incentive pay in excess of the IRS' eligible compensation limit for qualified plans, which is $245,000 for 2011, up to $2,000,000.

The Company matches 100% of the participant' s contributions up to 1% of eligible compensation and 70% of the participant' s contributions from the next 5% of eligible compensation.

Participants may not withdraw any amount credited to their account until their termination of employment with AEP. Participants may elect a distribution of their account as a lump-sum or annual installment payments over a period of up to 10 years. Participants may delay the commencement of distributions for up to five years from the date of their termination of employment.

Participants may direct the investment of their plan account among the investment options that are available to all employees in AEP' s qualified Retirement Savings Plan and one additional option that provides interest at a rate set each December at 120% of the applicable federal long-term rate with monthly compounding. There were no above-market or preferential earnings with respect to the Supplemental Retirement Savings Plan.

Incentive Compensation Deferral Plan. This plan allows eligible employees to defer payment of up to 80% of earned performance units.

AEP does not offer any matching contributions.

Participants may direct the investment of their plan accounts among the investment options that are available to all employees in AEP' s qualified Retirement Savings Plan. There were no above-market or preferential earnings with respect to the Incentive Compensation Deferral Plan.

Generally, participants may not withdraw any amount credited to their account until their termination of employment with AEP. However, participants may withdraw amounts attributable to their pre-2005 contributions once prior to termination of employment. The withdrawal amount would be subject to a 10% withdrawal penalty. Participants may elect to take distributions from their account in the same manner as described above for the Supplemental Retirement Savings Plan.

Stock Ownership Requirement Plan. This plan assists executives in achieving their minimum stock ownership requirements. It does this primarily by tracking the executive' s AEP Career Shares. AEP Career Shares are a form of deferred compensation, which are unfunded and unsecured general obligations of AEP. The rate of return on AEP Career Shares is equivalent to the total return on AEP stock with dividends reinvested. AEP Career Shares become payable in cash following the participant' s termination of employment. Participants may elect to take distribution of their AEP Career Shares in the same manner as described above for the Supplemental Retirement Savings Plan.

Potential Payments upon Termination or Change in Control

The Company has entered into agreements and maintains plans that will require the Company to provide compensation to the named executive officers in the event of a termination of their employment or a change in control of the Company.

SEVERANCE

AEP currently provides full-time employees, including the named executive officers, with severance benefits in the event their employment is terminated as the direct result of a restructuring or downsizing ("Severance-Eligible Employees") if the employee releases AEP from any and all claims. These severance benefits include:

A lump sum severance payment equal to two weeks of base pay for each year of Company service, except for Mr. Morris who would receive a severance payment equal to two times his annual base salary in the event of his severance pursuant to his employment agreement,

Continued eligibility for medical and dental benefits at the active employee rates for eighteen months or until the participant becomes eligible for coverage from another employer, whichever occurs first,

For employees who are at least age 50 with 10 years of AEP service and who do not qualify for AEP' s retiree medical benefits or to be bridged to such retiree benefit eligibility (described below), AEP also provides medical and dental benefit eligibility at rates equivalent to those provided to retirees until age 65 or until the participant becomes eligible for coverage from another employer, whichever occurs first, and

Outplacement services, the incremental cost of which may be up to $30,000 for executive officers.

Severance-Eligible Employees who have enough severance pay (up to one year) and vacation to cover a period that would allow them to become eligible for retiree medical benefits, which is available to those employees who are at least age 55 with at least 10 years of service ("Retirement-Eligible Employees") are retained as employees on a paid leave of absence until they become retirement eligible. This benefit applies in lieu of severance and unused vacation payments that these employees would otherwise receive. The Company pays any remaining severance and vacation pay at the time of their retirement. This delay of an employee' s termination date does not apply to the plans providing nonqualified deferred compensation, which define a participant' s termination date by reference to Code Section 409A.

Although employees generally must be employed through year-end to be eligible for annual incentive compensation, Severance-Eligible Employees and Retirement-Eligible Employees remain eligible for annual incentive compensation, to the extent of their eligible earnings, for the year of their termination. The target award for these employees reflects their cumulative base earnings for the plan year, which will be less than a full year of base earnings to the extent that the employee was not employed by the Company for the full plan year. Annual incentive awards for named executive officers continue to be subject to the performance-based maximum award limits of the Senior Officer Incentive Plan and the discretion of the HR Committee. Any annual incentive awards for severed or retired executive officers would be paid at approximately the same time as the awards for active employees.

A Severance-Eligible executive' s termination entitles that executive to a pro-rata portion of any outstanding performance units which the executive has held for at least six months. These prorated performance units will not become payable until the end of the performance period and remain subject to all performance objectives.

Severance-Eligible executives are eligible for continuation of financial counseling and tax preparation services one year following their termination up to a maximum annual incremental cost to the Company of $17,200.

CHANGE IN CONTROL

AEP defines "change in control" under its change in control agreements and long term incentive plan as:

The acquisition by any person of the beneficial ownership of securities representing more than one-third of AEP' s voting stock,

A merger or consolidation of AEP with another corporation unless AEP' s voting securities outstanding immediately before such merger or consolidation continue to represent at least two-thirds of the total voting power of the surviving entity outstanding immediately after such merger or consolidation, or

Approval by the shareholders of the liquidation of AEP or the disposition of all or substantially all of the assets of AEP.

AEP has a change in control agreement with each of the named executive officers, which is triggered if there is a Qualifying Termination of the named executive officer' s employment. A "Qualifying Termination" for this purpose generally occurs when the executive' s employment is terminated in connection with that change in control (i) by AEP without "cause" or (ii) by the named executive officer for "good reason." Such termination must be within one year before or two years after the change in control. These agreements provide for:

A lump sum payment equal to 2.99 times the named executive officers' annual base salary plus target annual incentive under the annual incentive program,

Payment, if required, to make the named executive officer whole for any excise tax imposed by Section 4999 of the Internal Revenue Code, and

Outplacement services.

The Company will reduce the lump sum change in control benefit payment for each of the named executive officers by up to 5% if that reduction would avoid the 4999 excise tax. In November 2009 the HR Committee revised the change in control agreements offered to new participants to eliminate the reimbursement for excise taxes.

The term "cause" with respect to AEP' s change in control agreements means:

(i) The willful and continued failure of the executive to perform the executive' s duties after a written demand for performance is delivered to the executive by the Board, or

(ii) The willful conduct or omission by the executive, which the Board determines to be illegal; gross misconduct that is injurious to the Company; or a breach of the executive' s fiduciary duty to the Company.

The term "good reason" with respect to AEP' s change in control agreements means:

(i) An adverse change in the executive' s status, duties or responsibilities from that in effect immediately prior to the change in control,

(ii) The Company' s failure to pay in a timely fashion the salary or benefits to which the executive is entitled under any employment agreement in effect on the date of the change in control,

(iii) The reduction of the executive' s salary as in effect on the date of the change in control,

(iv) Any action taken by the Company that would substantially diminish the aggregate projected value of the executive' s awards or benefits under the Company' s benefit plans or policies,

(v) A failure by the Company to obtain from any successor the assent to the change in control agreement, or

(vi) The relocation, without the executive' s prior approval, of the office at which the executive is to perform services to a location that is more than fifty (50) miles from its location immediately prior to the change in control.

The Company must be given notice and an opportunity to cure any of these circumstances before they would be considered to be "good reason".

Also, award agreements issued under the Long-Term Incentive Plan with an effective date prior to January 1, 2011 provide that such awards will vest immediately upon a change in control. Long-Term Incentive Plan awards granted with an effective date on or after January 1, 2011, will vest upon a "Qualifying Termination" upon or within one year after a change in control. The term "Qualifying Termination" with respect to long-term incentive awards generally is the same as that described for the change in control agreements, except that an executive' s mandatory retirement at age 65 is explicitly excluded and "Cause" is defined more broadly to encompass:

(i) Failure or refusal to perform assigned duties and responsibilities in a competent or satisfactory manner,

(ii) Commission of an act of dishonesty, including, but not limited to, misappropriation of funds or any property of AEP,

(iii) Engagement in activities or conduct injurious to the best interest or reputation of AEP,

(iv) Insubordination,

(v) A violation of any of a material term or condition of any written agreement with AEP,

(vi) Violation of any of AEP' s rules of conduct of behavior,

(vii) Commission of a felony, a misdemeanor involving an act of moral turpitude, or a misdemeanor committed in connection with employment with AEP which is injurious to the best interest or reputation of AEP, or

(viii) Disclosure, dissemination, or misappropriation of confidential, proprietary, and/or trade secret information.

In addition, certain types of long-term incentive awards are subject to special payment and valuation provisions if they vest upon a change in control as follows:

Stock Options - Participants with outstanding stock options are permitted to direct an advance exercise of any of their options and receive cash equal to the value received by other AEP shareholders as a result of the change in control transaction (less applicable tax withholdings).

Performance Unit Awards - The performance unit awards with an effective date prior to January 1, 2011 would be deemed to have been fully earned at 100% of the target score, and would be paid in a lump sum in cash upon a change in control. Performance units with an effective date on or after January 1, 2011 would be deemed to have been fully earned at 100% of the target score upon a "Qualifying Termination" (defined as described above for performance units issued on or after January 1, 2011) following a change in control. The value of each vested performance unit following a change in control or "Qualifying Termination" would be (1) if the payment is due upon a change in control that is the result of a tender offer, merger, or sale of all or substantially all of the assets of AEP, the price paid per share of common stock in that transaction, or (2), otherwise, the closing price of a share of AEP common stock on the date of the change in control (or Qualifying Termination, if applicable).

The AEP Supplemental Benefit Plan also provides that all accrued supplemental retirement benefits become fully vested upon a change in control.

Termination Scenarios

The following tables show the incremental compensation and benefits that would have been paid to each named executive officer on December 31, 2010 under the circumstances cited in each column.

The values shown in the change in control column are triggered only if the named executive officer's employment is terminated under the circumstances (described above under Change In Control) that trigger the payment or provision of each of the types of compensation and benefits shown.

No information is provided for terminations due to disability, because it is not AEP's practice to terminate the employment of any employee so long as they remain eligible for AEP's long-term disability benefits. AEP successively provides sick pay and then long-term disability benefits for up to two years to employees with a disability that prevents them from returning to their job. Such disability benefits continue (generally until the employee reaches age 65) for employees that cannot perform any occupation for which they are reasonably qualified. Because disabled participants remain employed by the Company, they continue to vest in long-term incentive awards while they are disabled. AEP treats a participant's disability as a termination to the extent required by the regulations issued under Code Section 409A, but such terminations only trigger the payment of benefits that had previously vested. In addition, restricted stock unit awards granted effective on or after January 1, 2011 allow participants terminated due to disability to continue to vest as if their employment had continued.

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Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2010
For Michael G. Morris

Executive Benefits and Payments Upon Termination	Voluntary Termination or Retirement	Severance	For Cause Termination	Change-In-Control	Death
Compensation:					
Base Salary ($1.265 million)	$0	$2,530,000 (1)	$ 0	$3,782,350	$0
Annual Incentive for Completed Year(2)	$1,579,785	$1,579,785	$ 0	$1,579,785	$1,579,785
Other Payment for Annual Incentives(3)	$0	$0	$ 0	$4,160,585	$0
Long-Term Incentives:(4)					
Unvested Restricted Shares (66,667)(5)	$0	$0	$ 0	$0	$0
Unvested 2009-2011 Performance Units(6)	$0	$4,664,807	$ 0	$6,997,211	$4,664,807
Unvested 2010-2012 Performance Units(6)	$0	$1,952,191	$ 0	$5,856,573	$1,952,191
Benefits:					
Health and Welfare Benefits(7)	$0	$16,428	$ 0	$16,428	$11,935
Financial Counseling	$0	$17,200	$ 0	$17,200	$17,200
Outplacement Services(8)	$0	$30,000	$ 0	$30,000	$0
Other					

Change in Control Benefit Reduction(9)	$0	$0	$ 0	$	$0
Tax Gross-up Upon Change In Control(10)	$0	$0	$ 0	$0	$0
Total Incremental Compensation And Benefits	$1,579,785	$10,790,411	$ 0	$22,440,132	$8,225,918

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

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Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2010
For Brian X. Tierney

Executive Benefits and Payments Upon Termination	Voluntary Termination or Retirement	Severance	For Cause Termination	Change-In-Control	Death
Compensation:					
Base Salary ($465,000)	$ 0	$232,500	$ 0	$1,390,350	$0
Annual Incentive for Completed Year(2)	$ 395,471	$395,471	$ 0	$395,471	$395,471
Other Payment for Annual Incentives(3)	$ 0	$0	$ 0	$1,042,763	$0
Long-Term Incentives:(4)					
Unvested 2009-2011 Performance Units(6)	$ 0	$759,969	$ 0	$1,139,954	$759,969
Unvested 2010-2012 Performance Units(6)	$ 0	$441,571	$ 0	$1,324,712	$441,571
Restricted Stock Units	$ 0	$0	$ 0	$1,525,372	$1,525,372
Benefits:					
Health and Welfare Benefits(7)	$ 0	$22,978	$ 0	$22,978	$109,575
Financial Counseling	$ 0	$17,200	$ 0	$17,200	$17,200
Outplacement Services(8)	$ 0	$30,000	$ 0	$30,000	$0
Other					

Change in Control Benefit Reduction(9)	$ 0	$0	$ 0	$0	$0
Tax Gross-up Upon Change In Control(10)	$ 0	$0	$ 0	$2,533,795	$0
Total Incremental Compensation and Benefits	$ 395,471	$1,899,689	$ 0	$9,422,595	$3,249,158

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

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Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2010
For Robert P. Powers

Executive Benefits and Payments Upon Termination	Voluntary Termination or Retirement	Severance	For Cause Termination	Change-In-Control	Death
Compensation:					
Base Salary ($521,400)	$ 0	$260,700	$ 0	$1,558,986	$0
Annual Incentive for Completed Year(2)	$ 414,461	$414,461	$ 0	$414,461	$414,461
Other Payment for Annual Incentives(3)	$ 0	$0	$ 0	$1,091,290	$0
Long-Term Incentives:(4)					
Unvested 2009-2011 Performance Units(6)	$ 0	$1,075,035	$ 0	$1,612,552	$1,075,035
Unvested 2010-2012 Performance Units(6)	$ 0	$463,614	$ 0	$1,390,843	$463,614
Restricted Stock Units	$ 0	$0	$ 0	$1,525,372	$1,525,372
Benefits:					
Health and Welfare Benefits(7)	$ 0	$0	$ 0	$0	$0
Financial Counseling	$ 0	$17,200	$ 0	$17,200	$17,200
Outplacement Services(8)	$ 0	$30,000	$ 0	$30,000	$0
Other					

Change in Control Benefit Reduction(9)	$ 0	$0	$ 0	$0	$0
Tax Gross-up Upon Change In Control(10)	$ 0	$0	$ 0	$2,861,892	$0
Total Incremental Compensation and Benefits	$ 414,461	$2,261,010	$ 0	$10,502,596	$3,495,682

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

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Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2010
For Nicholas K. Akins

Executive Benefits and Payments Upon Termination	Voluntary Termination or Retirement	Severance	For Cause Termination	Change-In-Control	Death
Compensation:					
Base Salary ($512,600)	$ 0	$552,031	$ 0	$1,532,674	$0
Annual Incentive for Completed Year(2)	$ 377,818	$377,818	$ 0	$377,818	$377,818
Other Payment for Annual Incentives(3)	$ 0	$0	$ 0	$996,238	$0
Long-Term Incentives:(4)					
Unvested 2009-2011 Performance Units(6)	$ 0	$759,969	$ 0	$1,139,954	$759,969
Unvested 2010-2012 Performance Units(6)	$ 0	$340,563	$ 0	$1,021,688	$340,563
Restricted Stock Units	$ 0	$0	$ 0	$1,525,372	$1,525,372
Benefits:					
Health and Welfare Benefits(7)	$ 0	$22,978	$ 0	$22,978	$59,191
Financial Counseling	$ 0	$17,200	$ 0	$17,200	$17,200
Outplacement Services(8)	$ 0	$30,000	$ 0	$30,000	$0
Other					

Change in Control Benefit Reduction(9)	$ 0	$0	$ 0	$0	$0
Tax Gross-up Upon Change In Control(10)	$ 0	$0	$ 0	$3,005,438	$0
Total Incremental Compensation and Benefits	$ 377,818	$2,100,559	$ 0	$9,669,360	$3,080,113

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

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Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2010
For Carl L. English

Executive Benefits and Payments Upon Termination	Voluntary Termination or Retirement	Severance	For Cause Termination	Change-In-Control	Death
Compensation:					
Base Salary ($561,400)	$ 0	$151,146	$ 0	$1,678,586	$0
Annual Incentive for Completed Year(2)	$ 478,116	$478,116	$ 0	$478,116	$478,116
Other Payment for Annual Incentives(3)	$ 0	$0	$ 0	$1,258,939	$0
Long-Term Incentives:(4)					
Unvested 2009-2011 Performance Units(6)	$ 0	$1,637,210	$ 0	$2,455,815	$1,637,210
Unvested 2010-2012 Performance Units(6)	$ 0	$662,356	$ 0	$1,987,067	$662,356
Benefits:					
Health and Welfare Benefits(7)	$ 0	$16,428	$ 0	$16,428	$4,886
Financial Counseling	$ 0	$17,200	$ 0	$17,200	$17,200
Outplacement Services(8)	$ 0	$30,000	$ 0	$30,000	$0
Other					
Change in Control Benefit Reduction(9)	$ 0	$0	$ 0	$0	$0

Tax Gross-up Upon Change In Control(10)	$ 0	$0	$ 0	$3,133,540	$0
Total Incremental Compensation and Benefits	$ 478,116	$2,992,456	$ 0	$11,055,691	$2,799,768

Notes for the Potential Incremental Termination Scenario tables are provided collectively following the last such table.

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Potential Incremental Compensation and Benefits
That Would Have Been Provided as the Result of Employment Termination
as of December 31, 2010
For Venita McCellon-Allen

Executive Benefits and Payments Upon Termination	Voluntary Termination or Retirement	Severance	For Cause Termination	Change-In-Control	Death
Compensation:					
Base Salary ($409,000)	$ 0	$424,731	$ 0	$1,222,910	$0
Annual Incentive for Completed Year(2)	$ 301,893	$301,893	$ 0	$301,893	$301,893
Other Payment for Annual Incentives(3)	$ 0	$0	$ 0	$794,891	$0
Long-Term Incentives:(4)					
Unvested 2009-2011 Performance Units(6)	$ 0	$759,969	$ 0	$1,139,954	$759,969
Unvested 2010-2012 Performance Units(6)	$ 0	$309,080	$ 0	$927,241	$309,080
Restricted Stock Units	$ 0	$0	$ 0	$1,525,372	$1,525,372
Benefits:					
Health and Welfare Benefits(7)	$ 0	$22,978	$ 0	$22,978	$55,052
Financial Counseling	$ 0	$17,200	$ 0	$17,200	$17,200
Outplacement Services(8)	$ 0	$30,000	$ 0	$30,000	$0
Other					

Change in Control Benefit Reduction(9)	$ 0	$0	$ 0	$0	$0
Tax Gross-up Upon Change In Control(10)	$ 0	$0	$ 0	$2,349,420	$0
Total Incremental Compensation and Benefits	$ 301,893	$1,865,851	$ 0	$8,331,859	$2,968,566

(1) Mr. Morris' employment agreement provides a severance benefit equal to two times his base pay in the event his employment is terminated not for cause, as defined therein.

(2) Executive officers are eligible for an annual incentive award if they remain employed with AEP through year-end unless their employment is terminated for cause. The amount shown is the calculated bonus opportunity, as shown on page 35, but all annual incentives for executive officers are awarded at the discretion of the HR Committee or independent members of the board pursuant to the award determination process described in the Compensation Discussion and Analysis.

(3) Represents a severance payment of 2.99 times each named executive officer' s current target annual incentive as of December 31, 2010.

(4) The long-term incentive values shown represent the values that would be paid under such circumstances shown in each column, which are different from the values calculated in accordance with FASB ASC Topic 718.

(5) Mr. Morris' restricted shares would be forfeited upon termination prior to vesting unless the HR Committee determines that the circumstances of the termination warrant otherwise.

(6) The target value of performance unit awards are shown. However, except in the event of a change in control, performance criteria continue to apply to performance units that vest early and award payments are not accelerated.

(7) The amount reported upon severance or a change in control represents the cost to the Company of providing subsidized medical and dental benefits at active employee rates for 18 months for those named executive officers who are not retirement-eligible. The amount reported upon death represents the present value of the cost to the Company of providing 50% subsidized

medical coverage to the employee' s surviving spouse (until the spouse reaches age 65) and any surviving eligible dependent children (until each reaches age 26).

(8) Represents the maximum cost of Company paid outplacement services, which the Company provides through an unaffiliated third party vendor.

(9) Represents a reduction in the lump sum change in control benefit payment of up to 5% that applies for an executive officer if that reduction would avoid excise taxes under Section 4999 of the Internal Revenue Code.

(10) Represents a tax gross-up for the excise tax under section 4999 of the Internal Revenue Code, including all applicable taxes on this tax gross-up itself. The amount does not reflect any reductions attributable to non-compete agreements or other provisions to which the executive must agree in order to be eligible for change in control benefits.

The following table shows the value of previously earned and vested compensation and benefits that would have been provided to each named executive officer after a termination of his or her employment on December 31, 2010. These amounts were generally earned or vested over multiple years of service to the Company and only a portion is attributable to compensation for 2010.

Non-Incremental Post-Termination Compensation and Benefits on December 31, 2010

	Long-Term Incentives			Benefits		
Name	**Vested Stock Options (1)**	**Vested Performance Units (2)**	**AEP Career Shares (3)**	**Vacation Payout (4)**	**Post Retirement Benefits (5)**	**Deferred Compensation (6)**
Michael G. Morris	$777,780	$2,913,804	$6,803,962	$80,279	$4,274,574	$3,088,898
Brian X. Tierney	$−	$399,558	$527,467	$26,380	$630,516	$1,202,913
Robert P. Powers	$−	$683,476	$1,491,011	$10,027	$3,022,482	$2,299,112
Nicholas K. Akins	$−	$447,807	$1,119,482	$42,388	$584,482	$556,557
Carl L. English	$−	$1,045,255	$2,339,240	$52,901	$512,249	$481,995
Venita McCellon-Allen	$−	$447,807	$1,232,063	$11,405	$648,567	$308,266

(1) Represents the value that would have been realized had the named executive officer exercised his vested and outstanding stock options at the closing price of AEP common stock on December 31, 2010.

(2) Represents the value of performance units that vested on December 31, 2010 calculated using the market value of these shares on December 31, 2010. However, the actual value realized from these shares in February 2011 was based on the previous 20-day average closing market price of AEP common stock as of the vesting date. For a more detailed discussion of vesting of performance units, see page 56.

(3) Represents the value of AEP share equivalents deferred mandatorily into AEP' s Stock Ownership Requirement Plan calculated, using the market value of these shares on December 31, 2010. However, the actual value that would have been realized from these AEP share equivalents would have been determined using the previous 20-day average closing market price of AEP common stock as of the date of termination.

(4) Represents payment of accumulated but unused vacation for the current year and any carry-over from prior years.

(5) Represents the lump sum benefit calculated for the named executive officer pursuant to the terms of the AEP Retirement Plan, AEP Supplemental Benefit Plan and CSW Executive Retirement Plan, as applicable. For Mr. Powers, who was eligible to receive AEP' s retiree medical, dental and life insurance benefits, it also includes the actuarial present value of these postretirement welfare benefits.

(6) Includes balances from the Supplemental Retirement Savings Plan and Incentive Compensation Deferral Plans, but does not include AEP Career Share balances, which are listed separately in column (3).

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Share Ownership of Directors and Executive Officers

The following table sets forth the beneficial ownership of AEP Common Stock and stock-based units as of February 22, 2011 for all Directors, each of the persons named in the Summary Compensation Table and all Directors and executive officers as a group.

Unless otherwise noted, each person had sole voting and investment power over the number of shares of AEP Common Stock set forth across from his or her name. Fractions of shares and units have been rounded to the nearest whole number.

Name	Shares	Stock Units(a)	Retainer Deferral Plan Stock Units(b)	Options Exercisable Within 60 Days	Total
D. J. Anderson	–	–	–	–	0
E. R. Brooks	12,350	28,442	–	–	40,792
D. M. Carlton	7,431	28,442	–	–	35,873
J. F. Cordes	–	4,524	–	–	4,524
R. D. Crosby, Jr.	–	16,579	–	–	16,579
C. E. English	20,899	81,955	–	–	102,854
L. A. Goodspeed	–	17,254	–	–	17,254
T. Hoaglin	1,000	11,560	–	–	12,560
L. A. Hudson, Jr.	1,853 (d)	34,488	–	–	36,341
V. McCellon-Allen	1,032 (c)	85,346	–	–	86,378
M. G. Morris	262,996(g)	249,104	–	149,000	661,100
R. C. Notebaert	–	–	–	–	0
L. L. Nowell III	–	20,523	–	–	20,523

R. P. Powers	20,612 (c)	96,519	–	–	117,131
R. L. Sandor	1,092	28,442	3,380	–	32,914
K. D. Sullivan	–	29,968	9,464	–	39,432
B. X. Tierney	38,702 (c)	70,607	–	–	109,309
N. K. Akins	–	90,150	–	–	90,150
S. Martinez Tucker	1,532 (e)	7,969	–	–	9,501
J. F. Turner	–	9,883	–	–	9,883
All directors, nominees and executive officers as a group (22 persons)	375,546(f)	945,217	12,844	149,000	1,482,647

(a) This column includes amounts deferred in stock units and held under the Stock Unit Accumulation Plan for Non-Employee Directors and held under AEP' s various executive benefit plans. Includes the following numbers of career shares: Mr. Morris, 189,104; Mr. Akins, 35,071; Mr. English, 65,015; Ms. McCellon-Allen, 34,243; Mr. Powers, 41,440; Mr. Tierney, 14,660; and all directors and executive officers as a group, 501,530.

(b) This column reflects amounts held in the Retainer Deferral Plan for Non-Employee Directors.

(c) Includes share equivalents held in the AEP Retirement Savings Plan and the AEP Supplemental Retirement Savings Plan.

(d) Includes 750 shares held by family members of Dr. Hudson over which he disclaims beneficial ownership.

(e) Includes 32 shares held by family members of Ms. Tucker over which she disclaims beneficial ownership.

(f) Represents less than 1% of the total number of shares outstanding.

(g) Includes restricted shares that vest in November 2011, that include dividend and voting rights. However, the shares cannot be sold, transferred or pledged until they vest.

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Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires AEP' s executive officers, directors and persons who beneficially own more than 10% of AEP' s Common stock to file initial reports of ownership and reports of changes in ownership of AEP Common Stock with the SEC. Executive officers and directors are required by SEC regulations to furnish AEP with copies of all reports they file. Based solely on a review of the copies of such reports furnished to AEP and written representations from AEP' s executive officers and directors during the fiscal year ended December 31, 2010, AEP believes that all Section 16(a) filing requirements were met during 2010.

Share Ownership of Certain Beneficial Owners

Set forth below are the only persons or groups known to AEP as of February 28, 2011, with beneficial ownership of five percent or more of AEP Common Stock.

	AEP Shares	
Name, Address of Beneficial Owner	**Amount of Beneficial Ownership**	**Percent of Class**
BlackRock, Inc. 40 East 52nd Street New York, NY 10022	27,881,137(a)	5.798 %

(a) Based on the Schedule 13G filed with the SEC, BlackRock, Inc. reported that it has sole power to vote 27,881,137 shares and sole dispositive power for 27,881,137 shares.

Shareholder Proposals and Nominations

To be included in AEP' s proxy statement and form of proxy for the 2012 annual meeting of shareholders, any proposal which a shareholder intends to present at such meeting must be received by AEP, attention: Thomas G. Berkemeyer, Assistant Secretary, at AEP' s office at 1 Riverside Plaza, Columbus, OH 43215 by November 15, 2011.

Notice to nominate a director must include your name, address, and number of shares you own; the name, age, business address, residence address and principal occupation of the nominee and the number of shares beneficially owned by the nominee. It must also include all the information required in AEP' s Policy on Consideration of Candidates for Director Recommended by Shareholders. A copy of this Policy is posted on our website at *www.AEP.com*. All such notices must be received by AEP, attention: Thomas G. Berkemeyer, Assistant Secretary, at AEP' s office at 1 Riverside Plaza, Columbus, OH 43215 by November 15, 2011. The Assistant Secretary will forward the recommendations to the Committee on Directors and Corporate Governance for consideration.

For any proposal intended to be presented by a shareholder without inclusion in AEP' s proxy statement and form of proxy for the 2012 annual meeting, the proxies named in AEP' s form of proxy for that meeting will be entitled to exercise discretionary authority on that proposal unless AEP receives notice of the matter by January 29, 2012. However, even if notice is timely received, the proxies may nevertheless be entitled to exercise discretionary authority on the matter to the extent permitted by SEC regulations.

Solicitation Expenses

These proxies are being solicited by our Board of Directors. The costs of this proxy solicitation will be paid by AEP. Proxies will be solicited principally by mail and the internet, but some telephone or personal solicitations of holders of AEP Common Stock may be made. Any officers or employees of the AEP System who make or assist in such solicitations will receive no compensation, other than their regular salaries, for doing so. AEP will request brokers, banks and other custodians or fiduciaries holding shares in their names or in the names of nominees to forward copies of the proxy-soliciting materials to the beneficial owners of the shares held by them, and AEP will reimburse them for their expenses incurred in doing so at rates prescribed by the New York Stock Exchange. We have engaged Morrow & Co., LLC, 470 West Ave., Stamford, Connecticut 06902, to assist us with the solicitation of proxies for an estimated fee of $9,500, plus reasonable out-of-pocket expenses.

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1 Riverside Plaza
Columbus, OH 43215-2378

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IMPORTANT ANNUAL MEETING INFORMATION

000004

ENDORSEMENT_LINE______________ SACKPACK_____________

MR A SAMPLE
DESIGNATION (IF ANY)
ADD 1
ADD 2
ADD 3
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ADD 5
ADD 6

Using a **black ink** pen, mark your votes with an **X** as shown in this example. Please do not write outside the designated areas.

Admission Ticket

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Electronic Voting Instructions

You can vote by Internet or telephone!
Available 24 hours a day, 7 days a week!

Instead of mailing your proxy, you may choose one of the two voting methods outlined below to vote your proxy.

VALIDATION DETAILS ARE LOCATED BELOW IN THE TITLE BAR.

Proxies submitted by the Internet or telephone must be received by 1:00 a.m., Eastern Time, on April 26, 2011.

Vote by Internet

Log on to the Internet and go to **www.envisionreports.com/AEP**

Follow the steps outlined on the secured website.

Vote by telephone

Call toll free 1-800-652-VOTE (8683) within the USA, US territories & Canada any time on a touch tone telephone. There is **NO CHARGE** to you for the call.

Follow the instructions provided by the recorded message.

Annual Meeting Proxy Card & Admission Ticket

1234 5678 9012 345

q **IF YOU HAVE NOT VOTED VIA THE INTERNET OR TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE.** q

A **Proposals** – **The Board of Directors recommends a vote FOR all the nominees listed and FOR Proposals 2, 3 and 1 year for Proposal 4.**

1. Election of Directors: **For Against Abstain** **For Against Abstain** **For Against Abstain**

01 - David J. Anderson ☐ ☐ ☐ 02 - James F. Cordes ☐ ☐ ☐ 03 - Ralph D. Crosby, Jr. ☐ ☐ ☐

04 - Linda A. Goodspeed ☐ ☐ ☐ 05 - Thomas E. Hoaglin ☐ ☐ ☐ 06 - Lester A. Hudson, Jr. ☐ ☐ ☐

07 - Michael G. Morris ☐ ☐ ☐ 08 - Richard C. Notebaert ☐ ☐ ☐ 09 - Lionel L. Nowell III ☐ ☐ ☐

10 - Richard L. Sandor ☐ ☐ ☐ 11 - Kathryn D. Sullivan ☐ ☐ ☐ 12 - Sara Martinez Tucker ☐ ☐ ☐

13 - John F. Turner ☐ ☐ ☐

	For	Against	Abstain
2. Ratification of the appointment of Deloitte & Touche LLP as the Company' s independent registered public accounting firm for the fiscal year ending December 31, 2011.	☐	☐	☐
3. Advisory vote on executive compensation	☐	☐	☐

	1 Yr	2 Yrs	3 Yrs	Abstain
4 Advisory vote on the frequency of holding an advisory vote on executive compensation.	☐	☐	☐	☐

B Authorized Signatures – This section must be completed for your vote to be counted. – Date and Sign Below

Please sign exactly as name(s) appears hereon. Joint owners should each sign. When signing as attorney, executor, administrator, corporate officer, trustee, guardian, or custodian, please give full title.

Date (mm/dd/yyyy) – Please print date below.	Signature 1 – Please keep signature within the box.	Signature 2 – Please keep signature within the box.
/ /		

IF VOTING BY MAIL, YOU MUST COMPLETE SECTIONS A - C ON BOTH SIDES OF THIS CARD.

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American Electric Power Company, Inc.

2011 Annual Meeting of Shareholders and Admission Ticket

Tuesday April 26, 2011, at 9:30 a.m. Eastern Time

The Ohio State University' s Fawcett Center

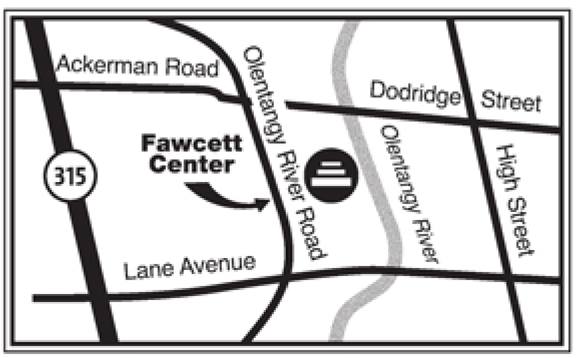
2400 Olentangy River Road

Columbus, Ohio

If you wish to attend and vote at the meeting, please bring this admission ticket and identification with you.

AGENDA

- **Introduction and Welcome**
- **Advisory vote on executive compensation**
- **Comments and Questions from Shareholders**
- **Election of Directors**
- **Advisory vote on frequency of holding an advisory vote on executive compensation**
- **Ratification of Auditors**
- **Chairman' s Report**



Directions to The Fawcett Center

(614) 292-1342

State Route 315 to the Lane Avenue exit.

Go East on Lane Avenue.

Take Lane Avenue to Olentangy River Road.

Turn North (a left turn) on Olentangy River Road.

The Fawcett Center is the first driveway on

the East (right) side of Olentangy River Road.

q **IF YOU HAVE NOT VOTED VIA THE INTERNET OR TELEPHONE, FOLD ALONG THE PERFORATION, DETACH AND RETURN THE BOTTOM PORTION IN THE ENCLOSED ENVELOPE.** q

AEP AMERICAN ELECTRIC POWER

+

Proxy − American Electric Power Company, Inc.

Proxy Solicited on behalf of the Board of Directors for the Annual Meeting to be held April 26, 2011

The shareholder signing on the reverse of this proxy card appoints Michael G. Morris, Carl L. English and Brian X. Tierney, and each of them, acting by a majority if more than one be present, attorneys and proxies to the undersigned, with power of substitution, to represent the undersigned at the annual meeting of shareholders of American Electric Power Company, Inc. to be held on April 26, 2011, and at any adjournment thereof, and to vote all shares of Common Stock of the Company which the undersigned is entitled to vote on all matters coming before said meeting. If no direction is given, such shares will be voted in accordance with the recommendations of the Board of Directors and at the discretion of the proxy holders as to any other matters coming before the meeting.

Trustee' s Authorization. The undersigned authorizes JP Morgan Chase Bank, National Association to vote all shares of Common Stock of the Company credited to the undersigned' s account under the American Electric Power System retirement savings plan at the annual meeting in accordance with instructions on the reverse side.

You are encouraged to specify your choices by marking the appropriate boxes (SEE REVERSE SIDE), but you need not mark any boxes if you wish to vote in accordance with the Board of Directors' recommendations.

Nominees for:

01 - David J. Anderson	02 - James F. Cordes	03 - Ralph D. Crosby, Jr.	04 - Linda A. Goodspeed	05 - Thomas E. Hoaglin	06 - Lester A. Hudson, Jr.
07 - Michael G. Morris	08 - Richard C. Notebaert	09 - Lionel L. Nowell III	10 - Richard L. Sandor	11 - Kathryn D. Sullivan	12 -Sara Martinez Tucker
13 - John F. Turner					

C **Non-Voting Items**

Change of Address − Please print new address below.

Comments − Please print your comments below.

IF VOTING BY MAIL, YOU MUST COMPLETE SECTIONS A - C ON BOTH SIDES OF THIS CARD.

Appendix A to the
Proxy Statement

American Electric Power

2010 Annual Report

Audited Consolidated Financial Statements and
Management's Financial Discussion and Analysis

AEP: America's Energy Partner®

AMERICAN ELECTRIC POWER
1 Riverside Plaza
Columbus, Ohio 43215-2373

CONTENTS

GLOSSARY OF TERMS

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

Term	Meaning
AEGCo	AEP Generating Company, an AEP electric utility subsidiary.
AEP or Parent	American Electric Power Company, Inc.
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, CSPCo, 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, CSPCo, I&M, KPCo and OPCo. The Pool shares the generation, cost of generation and resultant wholesale off-system sales of the member companies.
AEP System 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.
CAA	Clean Air Act.
CLECO	Cleco Corporation, 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, an AEP electric utility subsidiary.
CSW	Central and South West Corporation, a subsidiary of AEP (Effective January 21, 2003, the legal name of Central and South West Corporation was changed to AEP Utilities, Inc.).
CSW Operating Agreement	Agreement, dated January 1, 1997, as amended, by and among PSO and SWEPCo governing generating capacity allocation, energy pricing, and revenues and costs of third party sales. AEPSC acts as the agent.
CTC	Competition Transition Charge.
CWIP	Construction Work in Progress.
DCC Fuel	DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III 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.
ERCOT	Electric Reliability Council of Texas.
ERISA	Employee Retirement Income Security Act of 1974, as amended.
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 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 Utilities, Inc. 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	Agreement, dated July 6, 1951, as amended, by and among APCo, CSPCo, 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.
NO_x	Nitrogen oxide.
Nonutility Money Pool	AEP's Nonutility Money Pool.
NSR	New Source Review.
OCC	Corporation Commission of the State of Oklahoma.
OPCo	Ohio Power Company, an AEP electric utility subsidiary.
OPEB	Other Postretirement Benefit Plans.
OTC	Over the counter.
OVEC	Ohio Valley Electric Corporation, which is 43.47% owned by AEP.
PJM	Pennsylvania – New Jersey – Maryland regional transmission organization.
PM	Particulate Matter.
PSO	Public Service Company of Oklahoma, an AEP electric utility subsidiary.
PUCO	Public Utilities Commission of Ohio.

Term	Meaning
PUCT	Public Utility Commission of Texas.
Registrant Subsidiaries	AEP subsidiaries which are SEC registrants; APCo, CSPCo, 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.
Sabine	Sabine Mining Company, a lignite mining company that is a consolidated variable interest entity.
SIA	System Integration Agreement.
SNF	Spent Nuclear Fuel.
SO_2	Sulfur Dioxide.
SPP	Southwest Power Pool.
Stall Unit	J. Lamar Stall Unit at Arsenal Hill Plant.
SWEPCo	Southwestern Electric Power Company, an AEP electric utility subsidiary.
TA	Transmission Agreement dated April 1, 1984 by and among APCo, CSPCo, I&M, KPCo and OPCo, which allocates costs and benefits in connection with the operation of transmission assets.
TCC	AEP Texas Central Company, an AEP electric utility subsidiary.
TEM	SUEZ Energy Marketing NA, Inc. (formerly known as Tractebel Energy Marketing, Inc.).
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.
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 speak only 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.
- 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, including the Turk Plant, and transmission line 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 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.
- 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 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 related regulation 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 impacton 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.
- Other risks and unforeseen events, including wars, the effects of terrorism (including increased security costs), embargoes, cyber security threats and other catastrophic events.
- Our ability to recover through rates or prices any remaining unrecovered investment in generating units that may be retired before the end of their previously projected useful lives.

AEP and its Registrant Subsidiaries expressly disclaim any obligation to update any forward-looking information.

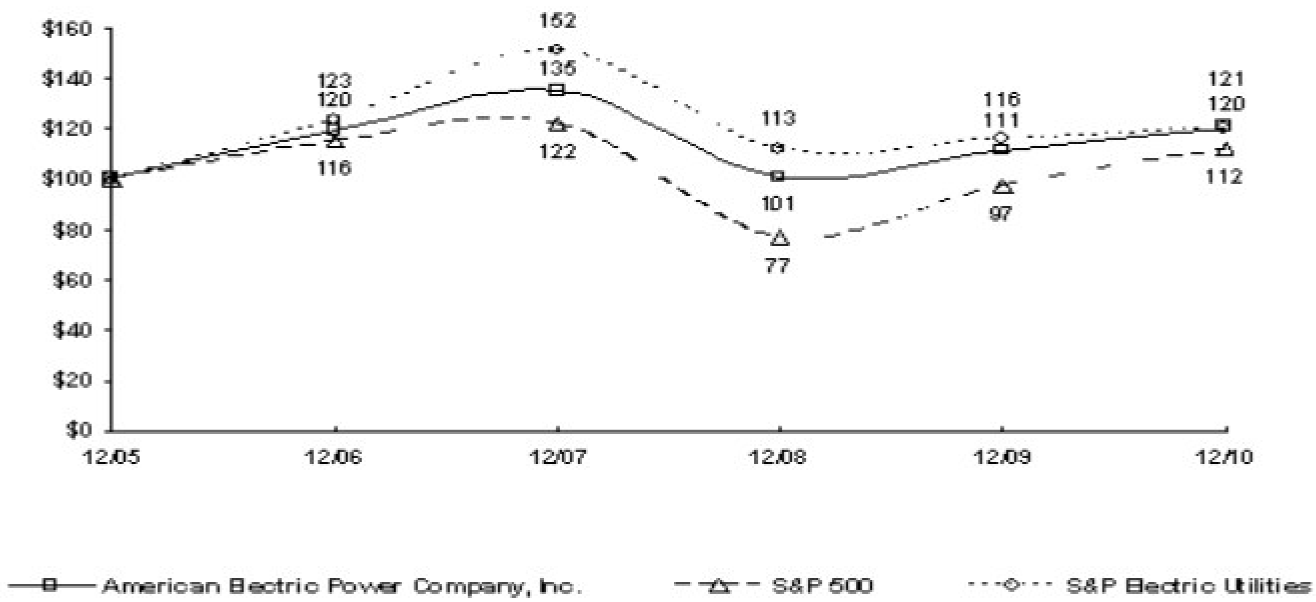
AEP COMMON STOCK AND DIVIDEND INFORMATION

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, 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
December 31, 2009	$ 36.51	$ 29.59	$ 34.79	$ 0.41
September 30, 2009	32.36	28.07	30.99	0.41
June 30, 2009	29.16	24.75	28.89	0.41
March 31, 2009	34.34	24.00	25.26	0.41

AEP common stock is traded principally on the New York Stock Exchange. At December 31, 2010, AEP had approximately 91,000 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 12/31/05 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

	2010	2009	2008	2007	2006
	(dollars in millions, except per share amounts)				
STATEMENTS OF INCOME DATA					
Total Revenues	$ 14,427	$ 13,489	$ 14,440	$ 13,380	$ 12,622
Operating Income	$ 2,663	$ 2,771	$ 2,787	$ 2,319	$ 1,966
Income Before Discontinued Operations and Extraordinary Loss	$ 1,218	$ 1,370	$ 1,376	$ 1,153	$ 1,001
Discontinued Operations, Net of Tax	-	-	12	24	10
Income Before Extraordinary Loss	1,218	1,370	1,388	1,177	1,011
Extraordinary Loss, Net of Tax	-	(5)	-	(79)	-
Net Income	1,218	1,365	1,388	1,098	1,011
Less: Net Income Attributable to Noncontrolling Interests	4	5	5	6	6
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,214	1,360	1,383	1,092	1,005
Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,211	$ 1,357	$ 1,380	$ 1,089	$ 1,002
BALANCE SHEETS DATA					
Total Property, Plant and Equipment	$ 53,740	$ 51,684	$ 49,710	$ 46,145	$ 42,021
Accumulated Depreciation and Amortization	18,066	17,340	16,723	16,275	15,240
Total Property, Plant and Equipment – Net	$ 35,674	$ 34,344	$ 32,987	$ 29,870	$ 26,781
Total Assets	$ 50,455	$ 48,348	$ 45,155	$ 40,319	$ 37,877
Total AEP Common Shareholders' Equity	$ 13,622	$ 13,140	$ 10,693	$ 10,079	$ 9,412
Noncontrolling Interests	$ -	$ -	$ 17	$ 18	$ 18
Cumulative Preferred Stock Not Subject to Mandatory Redemption	$ 60	$ 61	$ 61	$ 61	$ 61
Long-term Debt (a)	$ 16,811	$ 17,498	$ 15,983	$ 14,994	$ 13,698
Obligations Under Capital Leases (a)	$ 474 (b)	$ 317	$ 325	$ 371	$ 291
AEP COMMON STOCK DATA					

Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:					
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.40	$ 2.87	$ 2.52
Discontinued Operations, Net of Tax	-	-	0.03	0.06	0.02
Income Before Extraordinary Loss	2.53	2.97	3.43	2.93	2.54
Extraordinary Loss, Net of Tax	-	(0.01)	-	(0.20)	-
Total Basic Earnings per Share Attributable to AEP Common Shareholders	$ 2.53	$ 2.96	$ 3.43	$ 2.73	$ 2.54
Weighted Average Number of Basic Shares Outstanding (in millions)	479	459	402	399	394
Market Price Range:					
High	$ 37.94	$ 36.51	$ 49.11	$ 51.24	$ 43.13
Low	$ 28.17	$ 24.00	$ 25.54	$ 41.67	$ 32.27
Year-end Market Price	$ 35.98	$ 34.79	$ 33.28	$ 46.56	$ 42.58
Cash Dividends Paid per AEP Common Share	$ 1.71	$ 1.64	$ 1.64	$ 1.58	$ 1.50
Dividend Payout Ratio	67.59%	55.41%	47.8%	57.9%	59.1%
Book Value per AEP Common Share	$ 28.32	$ 27.49	$ 26.35	$ 25.17	$ 23.73

(a) Includes portion due within one year.

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

EXECUTIVE OVERVIEW

Company Overview

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

We operate an extensive portfolio of assets including:

- Almost 39,000 megawatts of generating capacity, one of the largest complements of generation in the U.S., the majority of which provides a significant cost advantage in most of our market areas.
- 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 220,000 miles of distribution lines that deliver electricity to 5.3 million customers.
- Substantial commodity transportation assets (more than 9,000 railcars, approximately 3,300 barges, 62 towboats, 29 harbor boats and a coal handling terminal with 18 million tons of annual capacity).

Economic Conditions

Retail margins increased during 2010 due to successful rate proceedings in various jurisdictions and higher residential and commercial demand for electricity as a result of favorable weather throughout our service territories. Industrial sales increased 5% in 2010 in comparison to the recessionary lows of 2009. We forecast a 1% increase in commercial sales and 2% increases in both our residential and industrial sales in 2011 as a result of anticipated slow economic growth. Our forecasted industrial sales growth of 2% is due to the announcement of increased production by Ormet, a large aluminum manufacturer in Ohio, and announced expansions of several refineries in our Texas service territory.

Regulatory Activity

The table below summarizes our significant 2010 regulatory activities:

Jurisdiction	Annual Approved Base Rate Change	Annual Rider Surcharge Rate Change	Approved Return on Common Equity	Effective Date
	(in millions)			
Kentucky	$ 63.7	$ -	10.50%	July 2010
Michigan	35.7	3.3 (a)	10.35%	December 2010
Oklahoma	30.3	(30.3)	10.15%	February 2011
Texas	15.0	10.0 (b)	10.33%	May 2010
Virginia	61.5	-	10.53%	August 2010

(a) The MPSC granted I&M recovery of $6.6 million of customer choice implementation costs over a two year period beginning April 2011.
(b) The PUCT granted SWEPCo a $10 million one-year surcharge rider to recover additional vegetation management costs which began in May 2010.

In Ohio, several notices of appeal are outstanding at the Supreme Court of Ohio relating to significant issues in the determination of the approved 2009 – 2011 ESP rates. In January 2011, the PUCO issued an order that determined that OPCo's 2009 earnings were not significantly excessive but determined relevant CSPCo 2009 earnings were significantly excessive. As a result, the PUCO ordered CSPCo to refund $43 million of its earnings to customers, which was recorded on CSPCo's December 2010 books. Also, in January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer pricing for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. Customer class rates individually vary, but on average, customers would experience net base generation increases of 1.4% in 2012 and 2.7% for the period January 2013 through May 2014.

In West Virginia, a settlement agreement was filed with the WVPSC in December 2010 to increase annual base rates by $60 million, effective March 2011. The settlement agreement allows APCo to defer and amortize up to $18 million of previously expensed 2009 incremental storm expenses over a period of eight years. A decision from the WVPSC is expected in March 2011.

Cost Reduction Initiatives

Due to the continued slow recovery in the U.S. economy and a corresponding negative impact on energy consumption, the AEP System implemented cost reduction initiatives in the second quarter of 2010 to reduce its workforce by 11.5% and reduce Other Operation and Maintenance spending. Achieving these goals involved identifying process improvements, streamlining organizational designs and developing other efficiencies that will deliver additional savings. In 2010, we recorded $293 million of pretax expense related to these cost reduction initiatives. Starting with the third quarter of 2010, we realized cost savings in Other Operation and Maintenance expenses on our Consolidated Statements of Income and anticipate continued savings to help offset future inflationary impacts.

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 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 cost $1.3 billion, excluding AFUDC, plus an additional $125 million for transmission, excluding AFUDC. The APSC, LPSC and PUCT approved SWEPCo's original application to build the Turk Plant. Various proceedings are pending that challenge the Turk Plant's construction, its approved wetlands and air permits and its transmission line certificate of environmental compatibility and public need. In 2010, the motions for preliminary injunction were partially granted and upheld on appeal pending a hearing. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. A hearing on SWEPCo's appeal is scheduled for March 2011.

In June 2010, the Arkansas Supreme Court denied motions for rehearing filed by the APSC and SWEPCo related to the reversal of the APSC's earlier grant of a Certificate of Environmental Compatibility and Public Need (CECPN) for SWEPCo's 88 MW Arkansas portion of the Turk Plant. As a result, in June 2010, SWEPCo filed notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of its Arkansas portion of Turk Plant costs in Arkansas retail rates. The APSC issued an order which reversed and set aside the previously granted CECPN.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition. See "Turk Plant" section of Note 4.

Settlement with Bank of America

In February 2011, we reached a settlement with BOA and paid $425 million in full settlement of all claims against us. We also received title to 55 BCF of cushion gas in the Bammel storage facility as part of the settlement. The effect of the settlement had no impact on our financial statements for the year ended December 31, 2010. We do not expect the effect of the settlement to have a material impact on our 2011 consolidated net income.

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 of December 31, 2010, approximately 5,000 Ohio retail customers (primarily CSPCo customers) have switched to alternative CRES providers. As a result, in comparison to 2009, we lost approximately $16 million of generation related gross margin in 2010 and currently forecast incremental lost margins of approximately $54 million for 2011. We anticipate recovery of a portion of this lost margin through off-system sales and our newly created CRES provider. Our CRES provider will target retail customers in Ohio, both within and outside of our retail service territory.

Termination of AEP Power Pool

Originally approved by the FERC in 1951 and subsequently amended in 1951, 1962, 1975 1979 (twice) and 1980, the Interconnection Agreement establishes the AEP Power Pool which permits the AEP East companies to pool their generation assets on a cost basis. In December 2010, each member gave notice to AEPSC and the other AEP Power Pool members of its decision to terminate the Interconnection Agreement effective January 1, 2014 or such other date approved by the FERC, subject to state regulatory input. It is unknown at this time whether the AEP Power Pool will be replaced by a new agreement among some or all of the members, whether individual companies will enter into bilateral or multi-party contracts with each other for power sales and purchases or asset transfers or if each company will choose to operate independently. The decision to terminate is subject to management's ongoing evaluation. The AEP Power Pool members may revoke their notices of termination. If members of the current AEP Power Pool experience decreases in revenues or increases in costs as a result of the termination of the AEP Power Pool and are unable to recover the change in revenues and costs through rates, prices or additional sales, it could have an adverse impact on future net income and cash flows.

Transmission Agreement

The AEP East companies are parties to a Transmission Agreement defining how they share the costs associated with their relative ownership of transmission assets. This sharing was based upon each company's MLR until the FERC approved a new Transmission Agreement effective November 1, 2010. The new Transmission Agreement will be phased-in for retail rates over periods of up to four years, adds KGPCo and WPCo as parties to the agreement and changes the allocation method. Our recovery mechanism for transmission costs is through our base rates. State regulatory phase-in of the new agreement may limit our ability to fully recover our transmission costs.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in a fire on the electric generator. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 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. I&M repaired Unit 1 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage 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 6.

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. See "Texas Restructuring Appeals" section of Note 4.

Mountaineer Carbon Capture and Storage

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In APCo's July 2009 Virginia base rate filing and May 2010 West Virginia base rate filing, APCo requested recovery of and a return on its Virginia and West Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the PVF costs, which resulted in a pretax write-off of approximately $54 million in the second quarter of 2010. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $60 million, effective March 2011. A decision from the WVPSC is expected in March 2011. As of December 31, 2010, APCo has recorded a noncurrent regulatory asset of $60 million related to the PVF. If APCo cannot recover its remaining investments in and expenses related to the PVF, it would reduce future net income and cash flows and impact financial condition. See "Mountaineer Carbon Capture and Storage Project" section of Note 4.

Carbon Capture and Sequestration Project with the Department of Energy (DOE)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale carbon capture and sequestration (CCS) facility under consideration at the Mountaineer Plant. AEPSC, on behalf of APCo, applied for and was selected to receive funding from the DOE for the project. The DOE will fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study, scheduled for completion during the third quarter of 2011, will refine the total cost estimate for the CCS facility. Results from the FEED study will be evaluated by management before any decision is made to seek the necessary regulatory approvals to build the CCS facility. As of December 31, 2010, APCo has incurred $14 million in total costs and has received $5 million of DOE funding resulting in a net $9 million balance included in Construction Work In Progress on the Consolidated Balance Sheets. If APCo is unable to recover the costs of the CCS project, it would reduce future net income and cash flows. See "Mountaineer Carbon Capture and Storage Project" section of Note 4.

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 state what the eventual resolution will be or the timing and amount of any loss, fine or penalty may be. We assess the probability of loss for each contingency and accrue a liability for cases that have a probable likelihood of loss if the loss can be estimated. For details on our regulatory proceedings and pending litigation see Note 4 – Rate Matters and Note 6 – Commitments, Guarantees and Contingencies. Adverse results in these proceedings have the potential to materially affect our net income.

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 from fossil fuel-fired power plants and new proposals governing the beneficial use and disposal of coal combustion products.

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 to reduce CO_2 emissions to address concerns about global climate change.

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. Notable developments in CAA regulatory requirements affecting our operations are discussed briefly below.

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. CAIR remains in effect while a new rulemaking is conducted. Nearly all of the states in which our power plants are located are covered by CAIR. In July 2010, the Federal EPA issued a proposed rule (Transport 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. Each state covered by the Transport Rule is assigned an allowance budget for SO_2 and/or NO_x. Limited interstate trading is allowed on a sub-regional basis and intrastate trading is allowed among generating units. Certain of our western states (Texas, Arkansas and Oklahoma) would be subject to only the seasonal NO_x program, with new limits that are proposed to take effect in 2012. The remainder of the states in which we operate would be subject to seasonal and annual NO_x programs and an annual SO_2 emissions reduction program that takes effect in two phases. The first phase becomes effective in 2012 and requires approximately one million tons per year more SO_2 emission reductions across the region than would have been required under CAIR. The second phase takes effect in 2014 and reduces SO_2 emissions by an additional 800,000 tons per year. The SO_2 and NO_x programs rely on newly-created allowances rather than relying on the CAIR NO_x allowances or the Title IV Acid Rain Program allowances used in the CAIR rule. The time frames for and stringency of the additional 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, as these features could accelerate unit retirements, increase capital requirements, constrain operations, decrease reliability and unfavorably impact financial condition if the increased costs are not recovered in rates or market prices. The Federal EPA requested comments on a scheme based exclusively on intrastate trading of allowances or a scheme that establishes unit-by-unit emission rates. Either of these options would provide less flexibility and exacerbate the negative impact of the rule. The proposal indicates that the requirements are expected to be finalized in June 2011 and be effective January 1, 2012.

The Federal EPA issued a Clean Air Mercury Rule (CAMR) setting mercury standards for new coal-fired power plants and requiring all states to issue new state implementation plans (SIPs) including mercury requirements for existing coal-fired power plants. The CAMR was vacated and remanded to the Federal EPA by the D.C. Circuit Court of Appeals in 2008.

Under the terms of a consent decree, the Federal EPA is required to issue final maximum achievable control technology (MACT) standards for coal and oil-fired power plants by November 2011. The Federal EPA has substantial discretion in determining how to structure the MACT standards. We will urge the Federal EPA to carefully consider all of the options available so that costly and inefficient control requirements are not imposed regardless of unit size, age or other operating characteristics. However, we have approximately 5,000 MW of older coal units, including 2,000 MW of older coal-fired capacity already subject to control requirements under the NSR consent decree, for which it may be economically inefficient to install scrubbers or other environmental controls. The timing and ultimate disposition of those units will be affected by: (a) the MACT standards and other environmental regulations, (b) the economics of maintaining the units, (c) demand for electricity, (d) availability and cost of replacement power and (e) regulatory decisions about cost recovery of the remaining investment in those units.

The Federal EPA issued a 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. CAVR will be implemented through individual SIPs or, if SIPs are not adequate or are not developed on schedule, through federal implementation plans (FIPs). The Federal EPA has proposed disapproval of SIPs in a few states, and proposed more stringent control requirements for affected units in those states. If the Federal EPA takes such action in the states where our facilities are located, 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 and final rules limiting CO_2 emissions from new motor vehicles in May 2010. 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. It is not possible at this time to estimate the costs of compliance with these new standards, but they may be material.

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.

Estimated Air Quality Environmental Investments

The CAIR, CAVR and the consent decree signed to settle the NSR litigation require us to make significant additional investments, some of which are estimable. Our estimates are subject to significant uncertainties and will be affected by any changes in the outcome of several interrelated variables and assumptions, including: (a) the timing of implementation, (b) required levels of reductions, (c) methods for allocation of allowances and (d) our selected compliance alternatives and their costs. These obligations may also be affected or altered by the development of new regulations described above. In short, we cannot estimate our compliance costs with certainty and the actual costs to comply could differ significantly from the estimates discussed below.

The CAIR, CAVR and commitments in the consent decree will require installation of additional controls on our power plants through 2020. We plan to install additional scrubbers on 6,770 MW for SO_2 control. From 2011 to 2020, we estimate total environmental investment to meet these requirements of $10.6 billion including investment in scrubbers and other SO_2 equipment of approximately $5.9 billion. These estimates are highly uncertain due to the variability associated with: (a) the states' implementation of these regulatory programs, including the potential for SIPs or FIPS that impose standards more stringent than CAIR or CAVR, (b) additional rulemaking activities in response to the court decisions remanding the CAIR and CAMR, (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 and (f) other factors. Associated operational and maintenance expenses will also increase during those years. We cannot estimate these additional operational and maintenance costs due to the uncertainties described above, but they are expected to be significant. Estimated construction expenditures are subject to periodic review and modification.

We will seek recovery of expenditures for pollution control technologies, replacement or additional generation and associated operating costs from customers through our regulated rates. We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, those costs could adversely affect future net income, cash flows and possibly financial condition.

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 our coal-fired electric generating units. The rule contains two alternative proposals, one that would impose federal hazardous waste disposal and management standards on these materials and one that 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.

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. We estimate that the potential compliance costs associated with the proposed solid waste management alternative could be as high as $3.9 billion for units across the AEP System. Regulation of these materials as hazardous wastes would significantly increase these costs. We will seek recovery of expenditures for pollution control technologies and associated costs from customers through our regulated rates (in regulated jurisdictions). We should be able to recover these expenditures through market prices in deregulated jurisdictions. If not, these costs could adversely affect future net income, cash flows and possibly financial condition.

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.

We believe that this is a global issue and that the United States should assume a leadership role in developing a new international approach that will address growing emissions of CO_2 and other greenhouse gases (generally referred to as CO_2 in this discussion) from all nations, including developing countries. We support a reasonable approach to CO_2 emission reductions that recognizes a reliable and affordable electric supply is vital to economic stability and that allows sufficient time for technology development. We proposed to national policy makers that national and international policy for reasonable CO_2 controls should involve the following principles:

- Comprehensiveness
- Cost-effectiveness
- Realistic emission reduction objectives
- Reliable monitoring and verification mechanisms
- Incentives to develop and deploy CO_2 reduction technologies
- Removal of regulatory or economic barriers to CO_2 emission reductions
- Recognition for early actions/investments in CO_2 reduction/mitigation
- Inclusion of adjustment provisions if largest emitters in developing world do not take action

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.”

While comprehensive economy-wide regulation of CO_2 emissions might be achieved through future legislation, Congress has yet to enact such legislation. The Federal EPA continues to take action to regulate CO_2 emissions under the existing requirements of the CAA discussed above.

Our fossil fuel-fired generating units are very 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 impact 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, cost recovery could 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. In addition, to the extent our costs are relatively higher than our competitors' costs, such as operators of nuclear and natural gas based 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 of our states have passed legislation establishing renewable energy, alternative energy and/or energy efficiency requirements (including Ohio, Michigan, 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 by an additional 2,000 MW from 2007 levels by 2011. By the end of 2010, we secured, through power purchase agreements, an additional 1,111 MW of wind power. To the extent demand for renewable energy from wind power increases, it could have a positive effect on future earnings from our transmission activities. For example, a project in Texas would build new transmission lines to transport electricity from planned wind energy generation in west Texas to more densely populated areas in eastern Texas.

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 2009, we reduced our emissions by a cumulative 94 million metric tons from adjusted baseline levels in 1998 through 2001 as a result of these voluntary actions. Our total CO_2 emissions in 2009 were 136 million metric tons. We estimate that our 2010 emissions were approximately 140 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 vigorously 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 6.

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 several decades and the extent and nature of those changes. Physical risks from climate change could include 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 to serve increased load, driving the overall cost of electricity higher. Decreased energy use due to weather changes 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.

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

RESULTS OF OPERATIONS

SEGMENTS

Our primary business is our electric utility operations. 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. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area and to a lesser extent Ohio in PJM and MISO. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

AEP River Operations

- Commercial barging operations that annually transport approximately 39 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 46% of the barging is for transportation of agricultural products, 25% for coal, 11% for steel and 18% for other commodities.

Generation and Marketing

- Wind farms and 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 (Loss) Before Discontinued Operations and Extraordinary Loss by segment for the years ended December 31, 2010, 2009 and 2008.

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Utility Operations	$ 1,201	$ 1,329	$ 1,123
AEP River Operations	37	47	55
Generation and Marketing	25	41	65
All Other (a)	(45)	(47)	133
Income Before Discontinued Operations and Extraordinary Loss	$ 1,218	$ 1,370	$ 1,376

(a) While not considered a business 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 are financial derivatives which settle and expire in 2011.

- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($ 164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

AEP CONSOLIDATED

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss in 2010 decreased $152 million compared to 2009 primarily due to $185 million of charges incurred (net of tax) related to cost reduction initiatives. In 2010, we conducted cost reduction initiatives to reduce both labor and non-labor expenses.

Average basic shares outstanding increased to 479 million in 2010 from 459 million in 2009 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 481 million as of December 31, 2010.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss in 2009 decreased $6 million compared to 2008 primarily due to income in 2008 from the cash settlement of a purchase power and sale agreement with TEM offset by an increase in income from our Utility Operations segment. The increase in Utility Operations segment net income primarily relates to rate increases in our Indiana, Ohio, Oklahoma and Virginia service territories partially offset by lower industrial sales as well as lower off-system sales margins due to lower sales volumes and lower market prices.

Average basic shares outstanding increased to 459 million in 2009 from 402 million in 2008 primarily due to the April 2009 issuance of 69 million shares of AEP common stock. Actual shares outstanding were 478 million as of December 31, 2009.

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,		
	2010	**2009**	**2008**
		(in millions)	
Total Revenues	$ 13,791	$ 12,803	$ 13,566
Fuel and Purchased Power	4,996	4,420	5,622
Gross Margin	8,795	8,383	7,944
Depreciation and Amortization	1,598	1,561	1,450
Other Operating Expenses	4,573	4,162	4,114
Operating Income	2,624	2,660	2,380
Other Income, Net	169	138	173
Interest Expense	942	916	915
Income Tax Expense	650	553	515
Income Before Discontinued Operations and Extraordinary Loss	$ 1,201	$ 1,329	$ 1,123

KWH Sales/Degree Days

Summary of KWH Energy Sales for Utility Operations

	Years Ended December 31, 2010	2009	2008
	(in millions of KWH)		
Retail:			
Residential	61,944	58,232	58,892
Commercial	50,748	49,925	50,382
Industrial	57,333	54,428	64,508
Miscellaneous	3,083	3,048	3,114
Total Retail (a)	173,108	165,633	176,896
Wholesale	32,581	29,670	43,068
Total KWHs	205,689	195,303	219,964

(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, 2010	2009	2008
	(in degree days)		
Eastern Region			
Actual - Heating (a)	3,222	3,018	3,154
Normal - Heating (b)	2,983	3,040	3,018
Actual - Cooling (c)	1,307	816	949
Normal - Cooling (b)	1,002	1,011	986
Western Region			
Actual - Heating (a)	1,112	970	992
Normal - Heating (b)	980	984	1,010
Actual - Cooling (d)	2,515	2,439	2,252
Normal - Cooling (b)	2,339	2,344	2,320

(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.

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 Loss
(in millions)

Year Ended December 31, 2009	$ 1,329
Changes in Gross Margin:	
Retail Margins	601
Off-system Sales	53
Transmission Revenues	15
Other Revenues	(257)
Total Change in Gross Margin	412
Total Expenses and Other:	
Other Operation and Maintenance	(351)
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	8
Total Expenses and Other	(443)
Income Tax Expense	(97)
Year Ended December 31, 2010	$ 1,201

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 $601 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 a refund provision for 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 $351 million primarily due to the following:
  - A $280 million increase due to expenses related to the cost reduction initiatives. In 2010, management conducted cost reduction initiatives to reduce both labor and non-labor expenses.
  - A $114 million increase in demand side management, energy efficiency and vegetation management programs and other related expenses. All of these expenses are currently recovered dollar-for-dollar in rate recovery riders/trackers in 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, CSPCo 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, CSPCo 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.

2009 Compared to 2008

Reconciliation of Year Ended December 31, 2008 to Year Ended December 31, 2009
Income from Utility Operations Before Discontinued Operations and Extraordinary Loss
(in millions)

Year Ended December 31, 2008	$ 1,123
Changes in Gross Margin:	
Retail Margins	549
Off-system Sales	(333)
Transmission Revenues	25
Other Revenues	198
Total Change in Gross Margin	439
Total Expenses and Other:	
Other Operation and Maintenance	(46)
Depreciation and Amortization	(111)
Taxes Other Than Income Taxes	(2)
Interest and Investment Income	(38)
Carrying Costs Income	(36)
Allowance for Equity Funds Used During Construction	37
Interest Expense	(1)
Equity Earnings of Unconsolidated Subsidiaries	2
Total Expenses and Other	(195)
Income Tax Expense	(38)
Year Ended December 31, 2009	$ 1,329

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 $549 million primarily due to the following:
  - Successful rate proceedings in our service territories which include:
    - A $187 million increase related to the PUCO's approval of our Ohio ESPs.
    - A $170 million increase related to base rates and recovery of E&R costs in Virginia and construction financing costs in West Virginia.
    - A $75 million net rate increase for PSO.
    - A $42 million net rate increase for I&M.
    - A $50 million net rate increase in our other jurisdictions.
  - A $201 million increase in fuel margins in Ohio primarily due to the deferral of fuel costs by CSPCo and OPCo in 2009. The PUCO's March 2009 approval of CSPCo's and OPCo's ESPs allows for the deferral of fuel and related costs related to the ESP period.
  - A $102 million increase due to the December 2008 provision for refund of off-system sales margins as ordered by the FERC related to the SIA.

- A $68 million increase due to lower PJM and other costs as the result of lower generation sales.

These increases were partially offset by:

- A $214 million decrease in margins from industrial sales due to reduced operating levels and suspended operations by certain large industrial customers in our service territories.
- A $78 million decrease in fuel margins due to higher fuel and purchased power costs related to the Cook Plant Unit 1 shutdown. This decrease in fuel margins was offset by a corresponding increase in Other Revenues as discussed below.
- A $52 million decrease in weather-related usage primarily due to a 14% decrease in cooling degree days in our eastern service territory.
- A $29 million decrease related to favorable coal contract amendments in 2008.

- **Margins from Off-system Sales** decreased $333 million primarily due to lower physical sales volumes and lower margins in our eastern service territory reflecting lower market prices, partially offset by higher trading and marketing margins.
- **Transmission Revenues** increased $25 million primarily due to increased rates in the ERCOT and SPP regions.
- **Other Revenues** increased $198 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 during the outage period. This decrease in insurance proceeds was offset by a corresponding increase in Retail Margins as discussed above.

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

- **Other Operation and Maintenance** expenses increased $46 million primarily due to the following:
  - The 2008 deferral of $74 million of previously expensed Oklahoma ice storm costs resulting from an OCC order approving recovery of January and December 2007 ice storm expenses.
  - A $64 million increase in administrative and general expenses primarily for employee benefits.
  - A $48 million increase in storm restoration expenses due to the December 2009 winter storm in Tennessee, Virginia and West Virginia.
  - A $32 million increase in demand side management, energy efficiency and vegetation management programs.
  - A $29 million increase in recoverable transmission service expenses.
  - A $14 million increase due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.

  These increases were partially offset by:
  - A $67 million decrease in distribution and customer account expenses.
  - A $51 million decrease in transmission expenses related to cost recovery rider amortization in Ohio and rate adjustment clause deferrals in Virginia.
  - A $43 million decrease in other operating expenses including lower charitable contributions.
  - A $39 million decrease in RTO fees, forestry and other transmission expenses.
  - A $15 million decrease in plant outages and other plant operating and maintenance expenses, including lower removal costs.
- **Depreciation and Amortization** increased $111 million primarily due to higher depreciable property balances as the result of environmental improvements placed in service at OPCo and various other property additions and higher depreciation rates for OPCo related to shortened depreciable lives for certain generating facilities.
- **Interest and Investment Income** decreased $38 million primarily due to lower interest income related to federal income tax refunds filed with the IRS and the recognition of other-than-temporary losses related to equity investments held by our protected cell of EIS in 2009.
- **Carrying Costs Income** decreased $36 million primarily due to the completion of reliability deferrals in Virginia in December 2008 and the decrease of environmental deferrals in Virginia in 2009.
- **Allowance for Equity Funds Used During Construction** increased $37 million as a result of construction at SWEPCo's Turk Plant and Stall Unit and the reapplication of "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective the second quarter of 2009.
- **Interest Expense** increased $1 million primarily due to a $52 million increase in interest expense related to increased long-term debt borrowings partially offset by interest expense of $47 million recorded in 2008 related to the 2008 SIA adjustment for off-system sales margins in accordance with the FERC's 2008 order.
- **Income Tax Expense** increased $38 million primarily due to an increase in pretax book income offset by the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

AEP RIVER OPERATIONS

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss 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.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our AEP River Operations segment decreased from $55 million in 2008 to $47 million in 2009 primarily due to lower revenues as a result of a weak import market.

GENERATION AND MARKETING

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss 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.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from our Generation and Marketing segment decreased from $65 million in 2008 to $41 million in 2009 primarily due to lower gross margins at the Oklaunion Generating Station as a result of lower power prices in ERCOT and decreased generation from our wind farm operations.

ALL OTHER

2010 Compared to 2009

Income Before Discontinued Operations and Extraordinary Loss from All Other increased from a loss of $47 million in 2009 to a loss of $45 million in 2010 primarily due to gains on the sale of our remaining shares of Intercontinental Exchange, Inc. (ICE) and a decrease in various parent related expenses partially offset by a contribution to AEP's charitable foundation and losses on the sales of assets.

2009 Compared to 2008

Income Before Discontinued Operations and Extraordinary Loss from All Other decreased from income of $133 million in 2008 to a loss of $47 million in 2009. In 2008, we had after-tax income of $164 million from a litigation settlement of a purchase power and sale agreement with TEM.

AEP SYSTEM INCOME TAXES

2010 Compared to 2009

Income Tax Expense increased $68 million in comparison to 2009 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.

2009 Compared to 2008

Income Tax Expense decreased $67 million in comparison to 2008 primarily due to a decrease in pretax book income and the regulatory accounting treatment of state income taxes and other book/tax differences which are accounted for on a flow-through basis.

FINANCIAL CONDITION

We measure our financial condition by the strength of our balance sheet and the liquidity provided by our cash flows. Target debt to equity ratios are usually maintained for each subsidiary and often credit arrangements contain ratios as covenants that must be met for borrowing to continue.

LIQUIDITY AND CAPITAL RESOURCES

Debt and Equity Capitalization

	December 31, 2010		December 31, 2009	
	(dollars in millions)			
Long-term Debt, including amounts due within one year	$ 16,811	52.8 %	$ 17,498	56.8 %
Short-term Debt	1,346	4.2	126	0.4
Total Debt	18,157	57.0	17,624	57.2
Preferred Stock of Subsidiaries	60	0.2	61	0.2
AEP Common Equity	13,622	42.8	13,140	42.6
Total Debt and Equity Capitalization	$ 31,839	100.0 %	$ 30,825	100.0 %

Our ratio of debt-to-total capital decreased from 57.2% in 2009 to 57% in 2010 primarily due to an increase in common equity.

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, 2010, we had $3.4 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, 2010, our available liquidity was approximately $2.5 billion as illustrated in the table below:

	Amount	Maturity
	(in millions)	
Commercial Paper Backup:		

	Revolving Credit Facility	$ 1,454	April 2012
	Revolving Credit Facility	1,500	June 2013
Revolving Credit Facility		478	April 2011
Total		3,432	
Cash and Cash Equivalents		294	
Total Liquidity Sources		3,726	
Less:	AEP Commercial Paper Outstanding	650	
	Letters of Credit Issued	601	
Net Available Liquidity		$ 2,475	

We have credit facilities totaling $3.4 billion, of which two $1.5 billion credit facilities support our commercial paper program. In June 2010, we terminated one of the $1.5 billion credit facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013. These credit facilities also allow us to issue letters of credit in an amount up to $1.35 billion. In June 2010, we also reduced the credit facility that matures in April 2011 from $627 million to $478 million. This facility is fully utilized for letters of credit providing liquidity support for Pollution Control Bonds. In March 2011, we intend to replace the revolving credit facility of $478 million with bilateral letters of credit or refinance the bonds. We may redeem some portion of the Pollution Control Bonds supported by the facility.

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 2010 was $868 million. The weighted-average interest rate for our commercial paper during 2010 was 0.43%.

Securitized Accounts Receivables

In 2010, we renewed our receivables securitization agreement. The agreement provides a commitment of $750 million from bank conduits to purchase receivables. A commitment of $375 million expires in July 2011 and the remaining commitment of $375 million expires in July 2013. We intend to extend or replace the agreement expiring in July 2011 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. At December 31, 2010, this contractually-defined percentage was 53.3%. Nonperformance under these covenants could result in an event of default under these credit agreements. At December 31, 2010, 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, 2010, we had not exceeded those authorized limits.

Dividend Policy and Restrictions

The Board of Directors declared a quarterly dividend of $0.46 per share in January 2011. 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, charter provisions 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, charter provisions 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,		
	2010	2009	2008
	(in millions)		
Cash and Cash Equivalents at Beginning of Period	$ 490	$ 411	$ 178
Net Cash Flows from Operating Activities	2,662	2,475	2,581
Net Cash Flows Used for Investing Activities	(2,523)	(2,916)	(4,027)
Net Cash Flows from (Used for) Financing Activities	(335)	520	1,679
Net Increase (Decrease) in Cash and Cash Equivalents	(196)	79	233
Cash and Cash Equivalents at End of Period	$ 294	$ 490	$ 411

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,		
	2010	2009	2008
	(in millions)		
Net Income	$ 1,218	$ 1,365	$ 1,388
Depreciation and Amortization	1,641	1,597	1,483
Other	(197)	(487)	(290)
Net Cash Flows from Operating Activities	$ 2,662	$ 2,475	$ 2,581

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.

Net Cash Flows from Operating Activities were $2.6 billion in 2008 consisting primarily of Net Income of $1.4 billion and $1.5 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. Net Cash Flows from Operating Activities increased in 2008 due to the TEM settlement. Under-recovered fuel costs and fuel, materials and supplies inventories increased working capital requirements due to the higher cost of coal and natural gas. Deferred Income Taxes increased primarily due to the enactment of the Economic Stimulus Act which enhanced expensing provisions for certain assets placed in service in 2008 and provided for a 50% bonus depreciation provision for certain assets placed in service in 2008.

Investing Activities

	Years Ended December 31,		
	2010	**2009**	**2008**
	(in millions)		
Construction Expenditures	$ (2,345)	$ (2,792)	$ (3,800)
Acquisitions of Nuclear Fuel	(91)	(169)	(192)
Acquisitions of Assets	(155)	(104)	(160)
Proceeds from Sales of Assets	187	278	90
Other	(119)	(129)	35
Net Cash Flows Used for Investing Activities	$ (2,523)	$ (2,916)	$ (4,027)

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 and distribution 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.

Net Cash Flows Used for Investing Activities were $4 billion in 2008 primarily due to Construction Expenditures for distribution, environmental and new generation investments.

Financing Activities

	Years Ended December 31,		
	2010	**2009**	**2008**
	(in millions)		
Issuance of Common Stock, Net	$ 93	$ 1,728	$ 159
Issuance/Retirement of Debt, Net	497	(360)	2,266
Dividends Paid on Common Stock	(824)	(758)	(666)
Other	(101)	(90)	(80)
Net Cash Flows from (Used for) Financing Activities	$ (335)	$ 520	$ 1,679

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.

Net Cash Flows from Financing Activities were $1.7 billion in 2008 primarily due to the borrowing under our credit facility to provide liquidity during the 2008 credit market. We paid common stock dividends of $666 million.

The following financing activities occurred during 2010:

AEP Common Stock:

- During 2010, we issued 3 million shares of common stock under our incentive compensation, employee savings and dividend reinvestment plans and received net proceeds of $93 million.

Debt:

- During 2010, we issued approximately $1.3 billion of long-term debt, including $650 million of senior notes at interest rates ranging from 3.4% to 6.2%, $150 million of senior notes at a variable interest rate, $326 million of pollution control revenue bonds at interest rates ranging from 2.875% to 5.375%, $84 million of notes at a 4% interest rate and $68 million of notes at a variable interest rate. The proceeds from these issuances were used to fund long-term debt maturities and our construction programs.
- During 2010, we entered into $1 billion of interest rate derivatives and settled $172 million of such transactions. The settlements resulted in net cash payments of $6 million. As of December 31, 2010, we had in place $907 million of notional interest rate derivatives designated as cash flow and fair value hedges.

In 2011:

- In January 2011, TCC retired $92 million of its outstanding Securitization Bonds.
- In January 2011, PSO issued $250 million of 4.4% Senior Unsecured Notes due 2021.
- In January 2011, PSO gave notice to retire $200 million of 6% Senior Unsecured Notes due in 2032 on February 28, 2011.
- In February 2011, APCo issued $65 million of 2% Pollution Control Bonds due 2041 with a 2012 mandatory put date.
- We expect to refinance approximately $1 billion of the $1.3 billion of long-term debt that will mature in 2011.

BUDGETED CONSTRUCTION EXPENDITURES

We forecast approximately $2.5 billion and $2.6 billion of construction expenditures excluding AFUDC and capitalized interest for 2011 and 2012, respectively. For 2012 through 2014, we forecast annual construction expenditures to average between $2.6 billion and $3.1 billion. 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 and Dresden Plants. Both plants are scheduled for completion in 2012. We resumed work on Dresden in the first quarter of 2011. The 2011 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	$ 223

Generation		813
Transmission		594
Distribution		776
Other		100
Total	$	2,506

OFF-BALANCE SHEET ARRANGEMENTS

In prior periods, under a limited set of circumstances, we entered into off-balance sheet arrangements for various reasons including accelerating cash collections, 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 and transfers of customer accounts receivable that we enter in the normal course of business. The following identifies significant off-balance sheet arrangements:

AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under this agreement, AEP Credit securitizes an interest in a portion of the receivables it acquires from affiliated utilities with the bank conduits and receives cash. Effective January 1, 2010, we record the receivables and debt related to AEP Credit on our Consolidated Balance Sheet.

At December 31, 2009, AEP Credit had $631 million of securitized receivables outstanding. See "ASU 2009-16 'Transfers and Servicing' (ASU 2009-16)" section of Note 2.

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 each company are $887 million as of December 31, 2010.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it to AEGCo and I&M. Our subsidiaries account for the lease as an operating lease with the future payment obligations included in Note 13. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. We, as well as our subsidiaries, have no ownership interest in the Owner Trustee and do not guarantee its debt.

Railcars

In June 2003, we entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. We intend to maintain the lease for the full lease term of twenty years via the renewal options. The lease is accounted for as an operating lease. The future minimum lease obligation is $36 million for the remaining railcars as of December 31, 2010. 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, 2010, the maximum potential loss was approximately $25 million ($17 million, net of tax) 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 Consolidated Balance Sheets and other obligations disclosed in our footnotes. The following table summarizes our contractual cash obligations at December 31, 2010:

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)	$ 1,346	$ -	$ -	$ -	$ 1,346
Interest on Fixed Rate Portion of Long-term Debt (b)	909	1,709	1,467	7,778	11,863
Fixed Rate Portion of Long-term Debt (c)	752	2,009	2,431	10,947	16,139
Variable Rate Portion of Long-term Debt (d)	557	150	-	-	707
Capital Lease Obligations (e)	100	159	106	286	651
Noncancelable Operating Leases (e)	306	547	467	1,349	2,669
Fuel Purchase Contracts (f)	2,810	3,974	2,543	3,718	13,045
Energy and Capacity Purchase Contracts (g)	69	199	204	1,101	1,573
Construction Contracts for Capital Assets (h)	1,031	1,407	1,636	3,143	7,217
Total	$ 7,880	$ 10,154	$ 8,854	$ 28,322	$ 55,210

(a) Represents principal only excluding interest.
(b) Interest payments are estimated based on final maturity dates of debt securities outstanding at December 31, 2010 and do not reflect anticipated future refinancing, early redemptions or debt issuances.
(c) See "Long-term Debt" section of Note 14. Represents principal only excluding interest.
(d) See "Long-term Debt" section of Note 14. Represents principal only excluding interest. Variable rate debt had interest rates that ranged between 0.29% and 1.31% at December 31, 2010.
(e) See Note 13.
(f) Represents contractual obligations to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(g) Represents 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 $119 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, 2010, we expect to make contributions to our pension plans totaling $158 million in 2011. Estimated contributions of $158 million in 2012 and $158 million in 2013 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 80.3% funded as of December 31, 2010.

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, 2010, 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)	$ 601	$ -	$ -	$ -	$ 601
Guarantees of the Performance of Outside Parties (b)	-	-	-	65	65
Guarantees of Our Performance (c)	1,457	18	20	41	1,536
Total Commercial Commitments	$ 2,058	$ 18	$ 20	$ 106	$ 2,202

(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, debt service reserves and variable rate Pollution Control Bonds. 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 $601 million with maturities ranging from January 2011 to November 2011. See "Letters of Credit" section of Note 6.
(b) See "Guarantees of Third-Party Obligations" section of Note 6.
(c) We issued performance guarantees and indemnifications for energy trading and various sale agreements.

SIGNIFICANT TAX LEGISLATION

The 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 will have no material impact on net income or financial condition but will have a favorable impact on cash flows in 2011 and are expected to result in material future cash flow benefits.

TRANSMISSION INITIATIVES

AEP Transmission Company, LLC (Utility Operations segment)

In 2006, we formed AEP Transmission Company, LLC (AEP Transco). In 2009, AEP Transco formed seven wholly-owned transmission companies. Upon approval of FERC interim rates, the transmission companies began recognizing revenues in July 2010 for their respective investments in PJM and SPP. The transmission companies have been established in Ohio, Oklahoma and Michigan. Applications for establishment of AEP Kentucky Transmission Company, Inc. and AEP West Virginia Transmission Company, Inc. have been filed with the KPSC and the WVPSC, respectively, and are pending approval. Other filings with commissions will be made in 2011. These seven companies consist of:

AEP East Transmission companies:

- AEP Appalachian Transmission Company, Inc. (covering Virginia)
- AEP Indiana Michigan Transmission Company, Inc.
- AEP Kentucky Transmission Company, Inc.
- AEP Ohio Transmission Company, Inc.
- AEP West Virginia Transmission Company, Inc.

AEP West Transmission companies:

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

AEPSC and other AEP subsidiaries provide services to the transmission companies through service agreements. Therefore, the transmission companies do not have any employees.

AEP Transco owns all of the transmission companies' equity. The transmission companies do not have outstanding debt and have not received capital contributions. All of the transmission companies' capital needs are provided by Parent and AEP Transco. For the transmission companies listed above, we forecast approximately $160 million of construction expenditures for 2011.

Joint Venture Initiatives (Utility Operations segment)

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 Equity Method Investment at December 31, 2010	Approved Return on Equity
				(in thousands)		
ETT	Texas	2017	MEHC Texas	$ 3,100,000 (a)	$ 110,323	9.96 %
	(ERCOT)		Transco, LLC (50%)			
			AEP (50%)			
PATH (b)	West	2015 (c)	Allegheny Energy (50%)	2,100,000 (d)	23,621	14.3 %(e)
	Virginia		AEP (50%)			
Prairie Wind	Kansas	2014	Westar Energy (50%)	225,000	784	12.8 %
			ETA (50%) (f)			
Pioneer	Indiana	2016	Duke Energy (50%)	1,000,000	-	12.54 %
			AEP (50%)			

(a) In addition to ETT's current total estimated project costs of $3.1 billion, ETT plans to invest in additional transmission projects in ERCOT over the next several years. Future projects will be evaluated on a case-by-case basis.
(b) In September 2007, AEP Transmission Holding Company, LLC and AET PATH Company, LLC, a subsidiary of Allegheny Energy, Inc., 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 has directed the construction of the PATH Project and placement of the project into service by June 2015, at the latest.
(d) PATH consists of the "West Virginia Series," which is owned equally by subsidiaries of Allegheny Energy Inc. and AEP, and the "Allegheny Series" which is wholly-owned by a subsidiary of Allegheny Energy Inc. The total project is estimated to cost approximately $2.1 billion. Our estimated share of the project cost is approximately $700 million. In February 2011, the "Ohio Series" was dissolved, which was owned equally by subsidiaries of Allegheny Energy Inc. and AEP.
(e) An October 2010 FERC order set the 14.3% return on equity for hearing.
(f) Electric Transmission America, LLC (ETA) is a 50/50 joint venture with MidAmerican Energy Holdings Company (MEHC) America Transco, LLC and AEP Transmission Holding Company, LLC. ETA will be utilized as a vehicle to invest in selected transmission projects located in North America, outside of ERCOT. AEP Transmission Holding Company, LLC owns 25% of Prairie Wind through its ownership interest in ETA.

For our joint ventures listed above, we forecast approximately $113 million of equity contributions in 2011 to support construction and other expenditures.

MINE SAFETY INFORMATION

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 DHLC, CSPCo, through its ownership of Conesville Coal Preparation Company (CCPC), and OPCo, through its use of the Conner Run fly ash impoundment, are subject to the provisions of the Mine Act.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires companies that operate mines to include in their periodic reports filed with the SEC, certain mine safety information covered by the Mine Act. DHLC, CCPC and Conner Run received the following notices of violation and proposed assessments under the Mine Act for the quarter ended December 31, 2010:

	DHLC	CCPC	Conner Run
Number of Citations for Violations of Mandatory Health or Safety Standards under 104 *	1	-	-
Number of Orders Issued under 104(b) *	-	-	-
Number of Citations and Orders for Unwarrantable Failure to Comply with Mandatory Health or Safety Standards under 104(d) *	-	-	-
Number of Flagrant Violations under 110(b)(2) *	-	-	-
Number of Imminent Danger Orders Issued under 107(a) *	-	-	-
Total Dollar Value of Proposed Assessments	$ 1,026	$ -	$ -
Number of Mining-related Fatalities	-	-	-

* References to sections under the Mine Act

DHLC currently has two legal actions pending before the Mine Safety and Health Administration (MSHA) challenging four violations issued by MSHA following an employee fatality in March 2009.

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 consolidated 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 our expense recognition with the recovery of such expense in regulated revenues. Likewise, we match income with the regulated revenues from our customers in the same accounting period. 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. Examples of new events 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, 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 may also reduce future cash flows since there will be no recovery through regulated rates.

Effect if Different Assumptions Used

A change in the above assumptions may result in a material impact on our net income. Refer to Note 5 for further detail related to regulatory assets and 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 Consolidated Statements of Income were $46 million, $55 million and $72 million for the years ended December 31, 2010, 2009 and 2008, respectively. The increases in unbilled electric revenues are primarily due to rate increases and changes in weather. Accrued unbilled revenues for the Utility Operations segment were $549 million and $503 million as of December 31, 2010 and 2009, 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 10 and 11. See "Fair Value Measurements of Assets and Liabilities" section of Note 1 for fair value calculation policy.

Long-Lived Assets

Nature of Estimates Required

In accordance with the requirements of "Property, Plant and Equipment" accounting guidance, we evaluate long-lived assets for impairment whenever events or changes in circumstances indicate that the carrying amount of any such assets may not be recoverable 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 as approved by our regulators. 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, 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 to determine composite depreciation rates and related lives which are subject to periodic review by state regulatory commissions. The fair value of the asset could be different using different estimates and assumptions in these valuation techniques.

Effect if Different Assumptions Used

In connection with the evaluation of long-lived assets in accordance with the requirements of "Property, Plant and Equipment" accounting guidance, the fair value of an asset can vary if different estimates and assumptions would have been used in our applied valuation techniques. The estimate for depreciation rates takes into account the history of interim capital replacements and the amount of salvage expected. In cases of impairment, we made our best estimate of fair value using valuation methods based on the most current information at that time. Fluctuations in realized sales proceeds versus the estimated fair value of the asset are generally due to a variety of factors including, but not limited to, differences in subsequent market conditions, the level of bidder interest, timing and terms of the transactions and our analysis of the benefits of the transaction.

Pension and Other Postretirement Benefits

We maintain a qualified, defined benefit pension plan (Qualified Plan), which covers substantially all nonunion and certain union employees, and unfunded, nonqualified supplemental plans (Nonqualified Plans) to provide benefits in excess of amounts permitted under the provisions of the tax law 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 8 for information regarding costs and assumptions for employee retirement and postretirement benefits.

The following table shows the net periodic cost of the Plans:

	Years Ended December 31,		
Net Periodic Benefit Cost	**2010**	**2009**	**2008**
	(in millions)		
Pension Plans	$ 141	$ 96	$ 51
Postretirement Plans	111	141	80

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 2011, 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 7.75% for the Qualified Plan and 7.5% for the Postretirement Plans.

The expected long-term rate of return on the Plans' assets is based on our targeted asset allocation and our expected investment returns for each investment category. Our assumptions are summarized in the following table:

	Pension Plans		**Other Postretirement Benefit Plans**	
	2011 Target Asset Allocation	**Assumed/ Expected Long-Term Rate of Return**	**2011 Target Asset Allocation**	**Assumed/ Expected Long-Term Rate of Return**
Equity	50%	9.00%	66%	9.00%
Real Estate	5%	7.60%	-%	-%
Fixed Income	39%	5.75%	32%	5.75%
Other Investments	5%	10.50%	-%	-%
Cash and Cash Equivalents	1%	3.00%	2%	3.00%
Total	100%		100%	

We regularly review the actual asset allocation and periodically rebalance the investments to our targeted allocation. We believe that 7.75% for the Pension Plan and 7.5% for the Postretirement Plans are reasonable long-term rates of return on the Plans' assets despite the recent market volatility. The Pension Plan's assets had an actual gain of 13.4% and 17.1% for the years ended December 31, 2010 and 2009, respectively. The Postretirement Plans' assets had an actual gain of 11.3% and 23.7% for the years ended December 31, 2010 and 2009, 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, 2010, we had cumulative losses of approximately $285 million that remain to be recognized in the calculation of the market-related value of assets. These unrecognized net actuarial losses will 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, 2010 under this method was 5.05% for the Qualified Plan, 4.95% for the Nonqualified Plans and 5.25% 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 7.75%, discount rates of 5.05% and 4.95% and various other assumptions, we estimate that the pension costs for the Pension Plans will approximate $144 million, $166 million and $194 million in 2011, 2012 and 2013, respectively. Based on an expected rate of return on the Postretirement Plans' assets of 7.5%, a discount rate of 5.25% and various other assumptions, we estimate costs will approximate $82 million, $78 million and $74 million in 2011, 2012 and 2013, 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 Plan's assets increased to $3.9 billion at December 31, 2010 from $3.4 billion at December 31, 2009 primarily due to a $500 million contribution. During 2010, the Qualified Plan paid $465 million and the Nonqualified Plans paid $15 million in benefits to plan participants. The value of the Postretirement Plans' assets increased to $1.5 billion at December 31, 2010 from $1.3 billion at December 31, 2009 primarily due to investment gains and contributions. The Postretirement Plans paid $142 million in benefits to plan participants during 2010.

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
- Rate of compensation increase
- 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, 2010 Benefit Obligations				
Discount Rate	$ (233)	$ 256	$ (132)	$ 147
Compensation Increase Rate	11	(10)	-	-
Cash Balance Crediting Rate	43	(38)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	114	(101)
Effect on 2010 Periodic Cost				
Discount Rate	(20)	22	(12)	14
Compensation Increase Rate	4	(3)	1	(1)
Cash Balance Crediting Rate	10	(9)	N/A	N/A
Health Care Cost Trend Rate	N/A	N/A	18	(16)
Expected Return on Plan Assets	(20)	20	(6)	6

N/A Not Applicable

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines.

We maintain trust funds for each regulatory jurisdiction. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives. We record securities held in these trust funds as Spent Nuclear Fuel and

Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We utilize our trustee's external pricing service in our estimate of the fair value of the underlying investments held in these trusts. Our investment managers review and validate the prices utilized by the trustee to determine fair value. We perform our own valuation testing to verify the fair values of the securities. We receive audit reports of our trustee's operating controls and valuation processes. See "Investments Held in Trust for Future Liabilities" section of Note 1 and "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11.

NEW ACCOUNTING PRONOUNCEMENTS

New Accounting Pronouncements Adopted During 2010

We adopted ASU 2009-16 "Transfers and Servicing" effective January 1, 2010. The adoption of this standard resulted in AEP Credit's transfers of receivables being accounted for as financings with the receivables and short-term debt recorded on our balance sheet.

We adopted the prospective provisions of ASU 2009-17 "Consolidations" effective January 1, 2010. We no longer consolidate DHLC effective with the adoption of this standard.

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, emission allowances, fair value measurements, leases, insurance, hedge accounting, consolidation policy and discontinued operations. 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 AND CREDIT RISK

Market Risks

Our Utility Operations segment is exposed to certain market risks as a major power producer and transacts 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, operating primarily within ERCOT and to a lesser extent Ohio in PJM and MISO, primarily transacts in wholesale energy marketing contracts. This segment is exposed to certain market risks as a marketer of wholesale 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 includes natural gas operations which holds forward natural gas contracts that were not sold with the natural gas pipeline and storage assets. These contracts are financial derivatives, which gradually settle and completely expire in 2011. Our risk objective is to keep these positions generally risk neutral through maturity.

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 electricity, coal, natural gas and emission allowances and to a lesser degree other commodities 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 President, 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, 2009:

MTM Risk Management Contract Net Assets (Liabilities)
Year Ended December 31, 2010

	Utility Operations	Generation and Marketing	All Other	Total
		(in millions)		
Total MTM Risk Management Contract Net Assets (Liabilities) at December 31, 2009	$ 134	$ 147	$ (3)	$ 278
(Gain) Loss from Contracts Realized/Settled During the Period and Entered in a Prior Period	(81)	(16)	5	(92)
Fair Value of New Contracts at Inception When Entered During the Period (a)	17	8	-	25
Net Option Premiums Received for Unexercised or Unexpired Option Contracts Entered During the Period	(1)	-	-	(1)
Changes in Fair Value Due to Valuation Methodology Changes on Forward Contracts (b)	(2)	(2)	-	(4)
Changes in Fair Value Due to Market Fluctuations During the Period (c)	6	3	-	9
Changes in Fair Value Allocated to Regulated Jurisdictions (d)	18	-	-	18
Total MTM Risk Management Contract Net Assets at December 31, 2010	$ 91	$ 140	$ 2	233
Commodity Cash Flow Hedge Contracts				11
Interest Rate and Foreign Currency Cash Flow Hedge Contracts				21
Fair Value Hedge Contracts				6
Collateral Deposits				101
Total MTM Derivative Contract Net Assets at December 31, 2010				$ 372

(a) Reflects fair value on primarily long-term structured contracts which are typically with customers that seek fixed pricing to limit their risk against fluctuating energy prices. The contract prices are valued against market curves associated with the delivery location and delivery term. A significant portion of the total volumetric position has been economically hedged.
(b) Reflects changes in methodology in calculating the credit and discounting liability fair value adjustments.
(c) Market fluctuations are attributable to various factors such as supply/demand, weather, etc.
(d) Relates to the net gains (losses) of those contracts that are not reflected on the Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

See Note 10 – Derivatives and Hedging and Note 11 – Fair Value Measurements for additional information related to our risk management contracts. The following tables and discussion provide information on our credit risk and market volatility risk.

Credit Risk

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

We have risk management contracts with numerous counterparties. Since open risk management contracts are valued based on changes in market prices of the related commodities, our exposures change daily. As of December 31, 2010, our credit exposure net of collateral to sub investment grade counterparties was approximately 5.3%, 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, 2010, 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	$ 666	$ 19	$ 647	1	$ 189
Split Rating	2	-	2	1	2
Noninvestment Grade	4	3	1	2	1
No External Ratings:					
Internal Investment Grade	215	-	215	2	123
Internal Noninvestment Grade	59	11	48	1	32
Total as of December 31, 2010	$ 946	$ 33	$ 913	7	$ 347
Total as of December 31, 2009	$ 846	$ 58	$ 788	12	$ 317

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, 2010, 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, 2010				Twelve Months Ended December 31, 2009			
End	High	Average	Low	End	High	Average	Low
(in millions)				(in millions)			
$-	$2	$1	$-	$1	$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, 2010 and 2009, the estimated EaR on our debt portfolio for the following twelve months was $5 million and $4 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, 2010 and 2009, and the related consolidated statements of income, changes in equity and comprehensive income (loss), and cash flows for each of the three years in the period ended December 31, 2010. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted FASB Accounting Standards Update No. 2009-16, *Transfers and Servicing (Topic 860): Accounting for Transfers of Financial Assets*, effective January 1, 2010.

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, 2010, 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 25, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ Deloitte & Touche LLP

Columbus,Ohio
February 25, 2011

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, 2010, 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, 2010, 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, 2010 of the Company and our report dated February 25, 2011 expressed an unqualified opinion on those financial statements and included an explanatory paragraph relating to the Company's adoption of a new accounting pronouncement.

/s/ Deloitte & Touche LLP

Columbus, Ohio
February 25, 2011

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, 2010. 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, 2010.

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, 2010, 2009 and 2008
(in millions, except per-share and share amounts)

	2010	2009	2008
REVENUES			
Utility Operations	$ 13,687	$ 12,733	$ 13,326
Other Revenues	740	756	1,114
TOTAL REVENUES	14,427	13,489	14,440
EXPENSES			
Fuel and Other Consumables Used for Electric Generation	4,029	3,478	4,474
Purchased Electricity for Resale	1,000	1,053	1,281
Other Operation	3,132	2,620	2,856
Maintenance	1,142	1,205	1,053
Gain on Settlement of TEM Litigation	-	-	(255)
Depreciation and Amortization	1,641	1,597	1,483
Taxes Other Than Income Taxes	820	765	761
TOTAL EXPENSES	11,764	10,718	11,653
OPERATING INCOME	2,663	2,771	2,787
Other Income (Expense):			
Interest and Investment Income	38	11	57
Carrying Costs Income	70	47	83
Allowance for Equity Funds Used During Construction	77	82	45
Interest Expense	(999)	(973)	(957)
INCOME BEFORE INCOME TAX EXPENSE AND EQUITY EARNINGS	1,849	1,938	2,015
Income Tax Expense	643	575	642
Equity Earnings of Unconsolidated Subsidiaries	12	7	3
INCOME BEFORE DISCONTINUED OPERATIONS AND EXTRAORDINARY LOSS	1,218	1,370	1,376
DISCONTINUED OPERATIONS, NET OF TAX	-	-	12
INCOME BEFORE EXTRAORDINARY LOSS	1,218	1,370	1,388
EXTRAORDINARY LOSS, NET OF TAX	-	(5)	-
NET INCOME	1,218	1,365	1,388
Less: Net Income Attributable to Noncontrolling Interests	4	5	5
NET INCOME ATTRIBUTABLE TO AEP SHAREHOLDERS	1,214	1,360	1,383

Less: Preferred Stock Dividend Requirements of Subsidiaries	3	3	3
EARNINGS ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 1,211	$ 1,357	$ 1,380
WEIGHTED AVERAGE NUMBER OF BASIC AEP COMMON SHARES OUTSTANDING	479,373,306	458,677,534	402,083,847
BASIC EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.40
Discontinued Operations, Net of Tax	-	-	0.03
Income Before Extraordinary Loss	2.53	2.97	3.43
Extraordinary Loss, Net of Tax	-	(0.01)	-
TOTAL BASIC EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.53	$ 2.96	$ 3.43
WEIGHTED AVERAGE NUMBER OF DILUTED AEP COMMON SHARES OUTSTANDING	479,601,442	458,982,292	403,640,708
DILUTED EARNINGS (LOSS) PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS			
Income Before Discontinued Operations and Extraordinary Loss	$ 2.53	$ 2.97	$ 3.39
Discontinued Operations, Net of Tax	-	-	0.03
Income Before Extraordinary Loss	2.53	2.97	3.42
Extraordinary Loss, Net of Tax	-	(0.01)	-
TOTAL DILUTED EARNINGS PER SHARE ATTRIBUTABLE TO AEP COMMON SHAREHOLDERS	$ 2.53	$ 2.96	$ 3.42
CASH DIVIDENDS PAID PER SHARE	$ 1.71	$ 1.64	$ 1.64

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CHANGES IN EQUITY AND COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2010, 2009 and 2008
(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, 2007	422	$ 2,743	$ 4,352	$ 3,138	$ (154)	$ 18	$ 10,097
Adoption of Guidance for Split-Dollar Life Insurance Accounting, Net of Tax of $6				(10)			(10)
Adoption of Guidance for Fair Value Accounting, Net of Tax of $0				(1)			(1)
Issuance of Common Stock	4	28	131				159
Reissuance of Treasury Shares			40				40
Common Stock Dividends				(660)		(6)	(666)
Preferred Stock Dividend Requirements of Subsidiaries				(3)			(3)
Other Changes in Equity			4				4
SUBTOTAL – EQUITY							9,620
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $2					4		4
Securities Available for Sale, Net of Tax of $9					(16)		(16)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $7					12		12
Pension and OPEB Funded Status, Net of Tax of $161					(298)		(298)
NET INCOME				1,383		5	1,388
TOTAL COMPREHENSIVE INCOME							1,090
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
COMPREHENSIVE INCOME							
Other Comprehensive Income, Net of Taxes:							
Cash Flow Hedges, Net of Tax of $4					7		7
Securities Available for Sale, Net of Tax of $6					11		11
Reapplication of Regulated Operations Accounting Guidance for Pensions, Net of Tax of $8					15		15
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $13					23		23
Pension and OPEB Funded Status, Net of Tax of $12					22		22
NET INCOME				1,360		5	1,365
TOTAL COMPREHENSIVE INCOME							1,443
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
COMPREHENSIVE INCOME							
Other Comprehensive Income (Loss), Net of Taxes:							
Cash Flow Hedges, Net of Tax of $14					26		26
Securities Available for Sale, Net of Tax of $4					(8)		(8)
Amortization of Pension and OPEB Deferred Costs, Net of Tax of $12					22		22
Pension and OPEB Funded Status, Net of Tax of $25					(47)		(47)
NET INCOME				1,214		4	1,218
TOTAL COMPREHENSIVE INCOME							1,211
TOTAL EQUITY – DECEMBER 31, 2010	501	$ 3,257	$ 5,904	$ 4,842	$ (381)	$ -	$ 13,622

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
ASSETS
December 31, 2010 and 2009
(in millions)

	2010	2009
CURRENT ASSETS		
Cash and Cash Equivalents	$ 294	$ 490
Other Temporary Investments		
(December 31, 2010 amount includes $287 related to Transition Funding and EIS)	416	363
Accounts Receivable:		
Customers	683	492
Accrued Unbilled Revenues	195	503
Pledged Accounts Receivable - AEP Credit	949	-
Miscellaneous	137	92
Allowance for Uncollectible Accounts	(41)	(37)
Total Accounts Receivable	1,923	1,050
Fuel	837	1,075
Materials and Supplies	611	586
Risk Management Assets	232	260
Accrued Tax Benefits	389	547
Regulatory Asset for Under-Recovered Fuel Costs	81	85
Margin Deposits	88	89
Prepayments and Other Current Assets	145	211
TOTAL CURRENT ASSETS	5,016	4,756
PROPERTY, PLANT AND EQUIPMENT		
Electric:		
Generation	24,352	23,045
Transmission	8,576	8,315
Distribution	14,208	13,549
Other Property, Plant and Equipment (including nuclear fuel and coal mining)	3,846	3,744
Construction Work in Progress	2,758	3,031
Total Property, Plant and Equipment	53,740	51,684
Accumulated Depreciation and Amortization	18,066	17,340
TOTAL PROPERTY, PLANT AND EQUIPMENT - NET	35,674	34,344
OTHER NONCURRENT ASSETS		
Regulatory Assets	4,943	4,595
Securitized Transition Assets	1,742	1,896
Spent Nuclear Fuel and Decommissioning Trusts	1,515	1,392
Goodwill	76	76
Long-term Risk Management Assets	410	343
Deferred Charges and Other Noncurrent Assets	1,079	946
TOTAL OTHER NONCURRENT ASSETS	9,765	9,248

TOTAL ASSETS	$ 50,455	$ 48,348

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED BALANCE SHEETS
LIABILITIES AND EQUITY
December 31, 2010 and 2009
(dollars in millions)

	2010	2009
CURRENT LIABILITIES		
Accounts Payable	$ 1,061	$ 1,158
Short-term Debt:		
Securitized Debt for Receivables - AEP Credit	690	-
Other Short-term Debt	656	126
Total Short-term Debt	1,346	126
Long-term Debt Due Within One Year	1,309	1,741
Risk Management Liabilities	129	120
Customer Deposits	273	256
Accrued Taxes	702	632
Accrued Interest	281	287
Regulatory Liability for Over-Recovered Fuel Costs	17	76
Deferred Gain and Accrued Litigation Costs	448	-
Other Current Liabilities	952	931
TOTAL CURRENT LIABILITIES	6,518	5,327
NONCURRENT LIABILITIES		
Long-term Debt		
(December 31, 2010 amount includes $1,857 related to Transition Funding, DCC Fuel and Sabine)	15,502	15,757
Long-term Risk Management Liabilities	141	128
Deferred Income Taxes	7,359	6,420
Regulatory Liabilities and Deferred Investment Tax Credits	3,171	2,909
Asset Retirement Obligations	1,394	1,254
Employee Benefits and Pension Obligations	1,893	2,189
Deferred Credits and Other Noncurrent Liabilities	795	1,163
TOTAL NONCURRENT LIABILITIES	30,255	29,820
TOTAL LIABILITIES	36,773	35,147
Cumulative Preferred Stock Not Subject to Mandatory Redemption	60	61
Rate Matters (Note 4)		
Commitments and Contingencies (Note 6)		
EQUITY		
Common Stock – Par Value – $6.50 Per Share:		

	2010	2009
Shares Authorized	600,000,000	600,000,000
Shares Issued	501,114,881	498,333,265

(20,307,725 shares and 20,278,858 shares were held in treasury at December 31, 2010 and 2009, respectively)	3,257	3,239
Paid-in Capital	5,904	5,824
Retained Earnings	4,842	4,451
Accumulated Other Comprehensive Income (Loss)	(381)	(374)
TOTAL AEP COMMON SHAREHOLDERS' EQUITY	13,622	13,140
TOTAL EQUITY	13,622	13,140
TOTAL LIABILITIES AND EQUITY	$ 50,455	$ 48,348

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2010, 2009 and 2008
(in millions)

	2010	2009	2008
OPERATING ACTIVITIES			
Net Income	$ 1,218	$ 1,365	$ 1,388
Adjustments to Reconcile Net Income to Net Cash Flows from Operating Activities:			
Depreciation and Amortization	1,641	1,597	1,483
Deferred Income Taxes	809	1,244	498
Provision for SIA Refund	-	-	149
Discontinued Operations, Net of Tax	-	-	(12)
Extraordinary Loss, Net of Tax	-	5	-
Carrying Costs Income	(70)	(47)	(83)
Allowance for Equity Funds Used During Construction	(77)	(82)	(45)
Mark-to-Market of Risk Management Contracts	30	(59)	(140)
Amortization of Nuclear Fuel	139	63	88
Pension Contributions to Qualified Plan Trust	(500)	-	-
Property Taxes	(21)	(17)	(13)
Fuel Over/Under-Recovery, Net	(253)	(474)	(272)
Gains on Sales of Assets, Net	(14)	(15)	(17)
Change in Other Noncurrent Assets	(75)	(137)	(244)
Change in Other Noncurrent Liabilities	202	244	8
Changes in Certain Components of Working Capital:			
Accounts Receivable, Net	(866)	41	71
Fuel, Materials and Supplies	221	(475)	(183)
Margin Deposits	1	(3)	(40)
Accounts Payable	(36)	8	(94)
Customer Deposits	14	2	(48)
Accrued Taxes, Net	179	(470)	4
Accrued Interest	(8)	17	30
Other Current Assets	72	(70)	(29)
Other Current Liabilities	56	(262)	82
Net Cash Flows from Operating Activities	2,662	2,475	2,581
INVESTING ACTIVITIES			
Construction Expenditures	(2,345)	(2,792)	(3,800)
Change in Other Temporary Investments, Net	(4)	16	45
Purchases of Investment Securities	(1,918)	(853)	(1,922)
Sales of Investment Securities	1,817	748	1,917
Acquisitions of Nuclear Fuel	(91)	(169)	(192)
Acquisitions of Assets	(155)	(104)	(160)
Proceeds from Sales of Assets	187	278	90
Other Investing Activities	(14)	(40)	(5)
Net Cash Flows Used for Investing Activities	(2,523)	(2,916)	(4,027)

FINANCING ACTIVITIES			
Issuance of Common Stock, Net	93	1,728	159
Issuance of Long-term Debt	1,270	2,306	2,774
Commercial Paper and Credit Facility Borrowings	565	127	2,055
Change in Short-term Debt, Net	770	119	(660)
Retirement of Long-term Debt	(1,993)	(816)	(1,824)
Commercial Paper and Credit Facility Repayments	(115)	(2,096)	(79)
Principal Payments for Capital Lease Obligations	(95)	(82)	(97)
Dividends Paid on Common Stock	(824)	(758)	(666)
Dividends Paid on Cumulative Preferred Stock	(3)	(3)	(3)
Other Financing Activities	(3)	(5)	20
Net Cash Flows from (Used for) Financing Activities	(335)	520	1,679
Net Increase (Decrease) in Cash and Cash Equivalents	(196)	79	233
Cash and Cash Equivalents at Beginning of Period	490	411	178
Cash and Cash Equivalents at End of Period	$ 294	$ 490	$ 411

See Notes to Consolidated Financial Statements.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
INDEX OF NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. ORGANIZATION AND SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

ORGANIZATION

The principal business conducted by seven of our electric utility operating companies is the generation, transmission and distribution of electric power. TCC exited the generation business and along with KGPCo and WPCo, provides only transmission and distribution services. TNC engages in the transmission and distribution of electric power and is a part owner in the Oklaunion Plant operated by PSO. TNC leases their entire portion of the output of the plant through 2027 to a nonutility affiliate. AEGCo is a regulated electricity generation business whose function is to provide power to our regulated electric utility operating companies. These companies are subject to regulation by the FERC under the Federal Power Act and the Energy Policy Act of 2005. These companies maintain accounts in accordance with the FERC and other regulatory guidelines. These companies are subject to further regulation with regard to rates and other matters by state regulatory commissions.

We also engage in wholesale electricity, natural gas and other commodity marketing and risk management activities in the United States. In addition, our operations include nonregulated wind farms and barging operations and we provide various energy-related services.

SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Rates and Service Regulation

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

The FERC regulates wholesale power markets and wholesale power transactions. Our wholesale power transactions are generally market-based. They are cost-based regulated when we negotiate and file a cost-based contract with the FERC or the FERC determines that we have "market power" in the region where the transaction occurs. We have entered into wholesale power supply contracts with various municipalities and cooperatives that are FERC-regulated, cost-based contracts. These contracts are generally formula rate mechanisms, which are trued up to actual costs annually. Our wholesale power transactions in the SPP region are cost-based due to PSO and SWEPCo having market power in the SPP region.

The state regulatory commissions regulate all of the distribution operations and rates of our retail public utilities on a cost basis. They also regulate the retail generation/power supply operations and rates except in Ohio and the ERCOT region of Texas. The ESP rates in Ohio continue the process of aligning generation/power supply rates over time with market rates. In the ERCOT region of Texas, the generation/supply business is under customer choice and market pricing and is conducted by REPs. Through its nonregulated subsidiaries, AEP enters into short and long-term wholesale transactions to buy or sell capacity, energy and ancillary services in the ERCOT market. In addition, these nonregulated subsidiaries control certain wind and coal-fired generation assets, the power from which is marketed and sold in ERCOT. Effective November 2009, AEP had no active REPs in ERCOT. SWEPCo operates in the SPP area which includes a portion of Texas. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations.

The FERC also regulates our wholesale transmission operations and rates. The FERC claims jurisdiction over retail transmission rates when retail rates are unbundled in connection with restructuring. CSPCo's and OPCo's retail transmission rates in Ohio, APCo's retail transmission rates in Virginia, I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled. CSPCo's and OPCo's retail transmission rates in Ohio and APCo's retail transmission rates in Virginia are based on the FERC's Open Access Transmission Tariff (OATT) rates that are cost-based. Although I&M's retail transmission rates in Michigan and TCC's and TNC's retail transmission rates in Texas are unbundled, retail transmission rates are regulated, on a cost basis, by the state regulatory commissions. Bundled retail transmission rates are regulated, on a cost basis, by the state commissions.

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

Principles of Consolidation

Our consolidated financial statements include our wholly-owned and majority-owned subsidiaries and variable interest entities (VIEs) of which we are the primary beneficiary. Intercompany items are eliminated in consolidation. We use the equity method of accounting for equity investments where we exercise significant influence but do not hold a controlling financial interest. Such investments are recorded as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets; equity earnings are included in Equity Earnings of Unconsolidated Subsidiaries on our Consolidated Statements of Income. We have ownership interests in generating units that are jointly-owned with nonaffiliated companies. Our proportionate share of the operating costs associated with such facilities is included on our Consolidated Statements of Income and our proportionate share of the assets and liabilities are reflected on our Consolidated Balance Sheets.

Variable Interest Entities

The accounting guidance for "Variable Interest Entities" is a consolidation model that considers if a company has a controlling financial interest in a VIE. A controlling financial interest will have both (a) the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and (b) the obligation to absorb losses of the VIE that could potentially be significant to the VIE or the right to receive benefits from the VIE that could potentially be significant to the VIE. Entities are required to consolidate a VIE when it is determined that they have a controlling financial interest in a VIE and therefore, are the primary beneficiary of that VIE, as defined by the accounting guidance for "Variable Interest Entities." In determining whether we are the primary beneficiary of a VIE, we consider factors such as equity at risk, the amount of the VIE's variability we absorb, guarantees of indebtedness, voting rights including kick-out rights, power to direct the VIE and other factors. We believe that significant assumptions and judgments were applied consistently. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

We are the primary beneficiary of Sabine, DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, AEP Credit, Transition Funding and a protected cell of EIS. As of January 1, 2010, we are no longer the primary beneficiary of DHLC as defined by the new accounting guidance for "Variable Interest Entities." In addition, we have not provided material financial or other support to Sabine, DCC Fuel LLC, DCC Fuel II LLC, DCC Fuel III LLC, Transition Funding, our protected cell of EIS and AEP Credit that was not previously contractually required. We hold a significant variable interest in Potomac-Appalachian Transmission Highline, LLC West Virginia Series (West Virginia Series) and DHLC.

Sabine is a mining operator providing mining services to SWEPCo. SWEPCo has no equity investment in Sabine but is Sabine's only customer. SWEPCo guarantees the debt obligations and lease obligations of Sabine. Under the terms of the note agreements, substantially all assets are pledged and all rights under the lignite mining agreement are assigned to SWEPCo. The creditors of Sabine have no recourse to any AEP entity other than SWEPCo. Under the provisions of the mining agreement, SWEPCo is required to pay, as a part of the cost of lignite delivered, an amount equal to mining costs plus a management fee. In addition, SWEPCo determines how much coal will be mined for each year. Based on these facts, management concluded that SWEPCo is the primary beneficiary and is required to consolidate Sabine. SWEPCo's total billings from Sabine for the years ended December 31, 2010, 2009 and 2008 were $133 million, $ 99 million and $110 million, respectively. See the tables below for the classification of Sabine's assets and liabilities on our Consolidated Balance Sheets.

Our subsidiaries participate in one protected cell of EIS for approximately ten lines of insurance. EIS has multiple protected cells. Neither AEP nor its subsidiaries have an equity investment in EIS. The AEP System is essentially this EIS cell's only participant, but allows certain third parties access to this insurance. Our subsidiaries and any allowed third parties share in the insurance coverage, premiums and risk of loss from claims. Based on our control and the structure of the protected cell and EIS, management concluded that we are the primary beneficiary of the protected cell and are required to consolidate its assets and liabilities. Our insurance premium payments to the protected cell for the years ended December 31, 2010, 2009 and 2008 were $ 35 million, $30 million and $ 28 million, respectively. See the tables below for the classification of the protected cell's assets and liabilities on our Consolidated Balance Sheets. The amount reported as equity is the protected cell's policy holders' surplus.

In September 2009, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel LLC. In April 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel II LLC. In December 2010, I&M entered into a nuclear fuel sale and leaseback transaction with DCC Fuel III LLC. DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC (collectively DCC Fuel) were formed for the purpose of acquiring, owning and leasing nuclear fuel to I&M. DCC Fuel purchased the nuclear fuel from I&M with funds received from the issuance of notes to financial institutions. Each entity is a single-lessee leasing arrangement with only one asset and is capitalized with all debt. DCC Fuel LLC, DCC Fuel II LLC and DCC Fuel III LLC are separate legal entities from I&M, the assets of which are not available to satisfy the debts of I&M. Payments on the DCC Fuel LLC and DCC Fuel II LLC leases are made semi-annually and began in April 2010 and October 2010, respectively. Payments on the DCC Fuel III LLC lease are made monthly and will begin in January 2011. Payments on the leases for the year ended December 31, 2010 were $59 million. No payments were made to DCC Fuel in 2009. The leases were recorded as capital leases on I&M's balance sheet as title to the nuclear fuel transfers to I&M at the end of the 48, 54 and 54 month lease term, respectively. Based on our control of DCC Fuel, management concluded that I&M is the primary beneficiary and is required to consolidate DCC Fuel. The capital leases are eliminated upon consolidation. See the tables below for the classification of DCC Fuel's assets and liabilities on our Consolidated Balance Sheets.

AEP Credit is a wholly-owned subsidiary of AEP. AEP Credit purchases, without recourse, accounts receivable from certain utility subsidiaries of AEP to reduce working capital requirements. AEP Parent provides a minimum of 5% equity and up to 20% of AEP Credit's short-term borrowing needs in excess of third party financings. Any third party financing of AEP Credit only has recourse to the receivables securitized for such financing. Based on our control of AEP Credit, management has concluded that we are the primary beneficiary and are required to consolidate its assets and liabilities. See the tables below for the classification of AEP Credit's assets and liabilities on our Consolidated Balance Sheets. See the "ASU 2009-17 'Consolidation' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010. Also, see "Securitized Accounts Receivables – AEP Credit" section of Note 14.

DHLC is a mining operator who sells 50% of the lignite produced to SWEPCo and 50% to CLECO. SWEPCo and CLECO share the executive board seats and its voting rights equally. Each entity guarantees a 50% share of DHLC's debt. SWEPCo and CLECO equally approve DHLC's annual budget. The creditors of DHLC have no recourse to any AEP entity other than SWEPCo. As SWEPCo is the sole equity owner of DHLC, it receives 100% of the management fee. Based on the shared control of DHLC's operations, management concluded as of January 1, 2010 that SWEPCo is no longer the primary beneficiary and is no longer required to consolidate DHLC. SWEPCo's total billings from DHLC for the years ended December 31, 2010, 2009 and 2008 were $ 56 million, $43 million and $ 44 million, respectively. See the tables below for the classification of DHLC's assets and liabilities on our Consolidated Balance Sheets at December 31, 2009 as well as our investment and maximum exposure as of December 31, 2010. As of January 1, 2010, DHLC is reported as an equity investment in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

Transition Funding was formed for the sole purpose of issuing and servicing securitization bonds related to Texas restructuring law. Management has concluded that TCC is the primary beneficiary of Transition Funding because

TCC has the power to direct the most significant activities of the VIE and TCC's equity interest could potentially be significant. Therefore, TCC is required to consolidate Transition Funding. The securitized bonds totaled $1.8 billion at December 31, 2010 and are included in current and long-term debt on the Consolidated Balance Sheets. Transition Funding has securitized transition assets of $1.7 billion at December 31, 2010, which are presented separately on the face of the Consolidated Balance Sheets. The securitized transition assets represent the right to impose and collect Texas true-up costs from customers receiving electric transmission or distribution service from TCC under recovery mechanisms approved by the PUCT. The securitization bonds are payable only from and secured by the securitized transition assets. The bondholders have no recourse to TCC or any other AEP entity. TCC acts as the servicer for Transition Funding's securitized transition assets and remits all related amounts collected from customers to Transition Funding for interest and principal payments on the securitization bonds and related costs.

The balances below represent the assets and liabilities of the VIEs that are consolidated. These balances include intercompany transactions that are eliminated upon consolidation.

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2010
(in millions)

	SWEPCo Sabine	I&M DCC Fuel	Protected Cell of EIS	AEP Credit	Transition Funding
ASSETS					
Current Assets	$ 50	$ 92	$ 131	$ 924	$ 214
Net Property, Plant and Equipment	139	173	-	-	-
Other Noncurrent Assets	34	112	1	10	1,746
Total Assets	$ 223	$ 377	$ 132	$ 934	$ 1,960
LIABILITIES AND EQUITY					
Current Liabilities	$ 33	$ 79	$ 33	$ 886	$ 221
Noncurrent Liabilities	190	298	85	1	1,725
Equity	-	-	14	47	14
Total Liabilities and Equity	$ 223	$ 377	$ 132	$ 934	$ 1,960

AMERICAN ELECTRIC POWER COMPANY, INC. AND SUBSIDIARY COMPANIES
VARIABLE INTEREST ENTITIES
December 31, 2009
(in millions)

	SWEPCo Sabine	SWEPCo DHLC	I&M DCC Fuel	Protected Cell of EIS
ASSETS				
Current Assets	$ 51	$ 8	$ 47	$ 130
Net Property, Plant and Equipment	149	44	89	-
Other Noncurrent Assets	35	11	57	2
Total Assets	$ 235	$ 63	$ 193	$ 132
LIABILITIES AND EQUITY				
Current Liabilities	$ 36	$ 17	$ 39	$ 36
Noncurrent Liabilities	199	38	154	74
Equity	-	8	-	22
Total Liabilities and Equity	$ 235	$ 63	$ 193	$ 132

Our investment in DHLC was:

	December 31, 2010	
	As Reported on the Consolidated Balance Sheets	Maximum Exposure
	(in millions)	
Capital Contribution from SWEPCo	$ 6	$ 6
Retained Earnings	2	2
SWEPCo's Guarantee of Debt	-	48
Total Investment in DHLC	$ 8	$ 56

In September 2007, we and Allegheny Energy Inc. (AYE) formed a joint venture by creating Potomac-Appalachian Transmission Highline, LLC (PATH). PATH is a series limited liability company and was created to construct a high-voltage transmission line project in the PJM region. PATH consists of the "Ohio Series," the "West Virginia Series (PATH-WV)," both owned equally by AYE and AEP, and the "Allegheny Series" which is 100% owned by AYE. Provisions exist within the PATH-WV agreement that make it a VIE. The "Ohio Series" does not include the same provisions that make PATH-WV a VIE. Neither the "Ohio Series" nor "Allegheny Series" are considered VIEs. We are not required to consolidate PATH-WV as we are not the primary beneficiary, although we hold a significant variable interest in PATH-WV. Our equity investment in PATH-WV is included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We and AYE share the returns and losses equally in PATH-WV. Our subsidiaries and AYE's subsidiaries provide services to the PATH companies through service agreements. At the current time, PATH-WV has no debt outstanding. However, when debt is issued, the debt to equity ratio in each series should be consistent with other regulated utilities. The entities recover costs through regulated rates.

Given the structure of the entity, we may be required to provide future financial support to PATH-WV in the form of a capital call. This would be considered an increase to our investment in the entity. Our maximum exposure to loss is to the extent of our investment. The likelihood of such a loss is remote since the FERC approved PATH-WV's request for regulatory recovery of cost and a return on the equity invested.

Our investment in PATH-WV was:

	December 31,			
	2010		2009	
	As Reported on the Consolidated Balance Sheets	Maximum Exposure	As Reported on the Consolidated Balance Sheets	Maximum Exposure
	(in millions)			
Capital Contribution from AEP	$ 18	$ 18	$ 13	$ 13
Retained Earnings	6	6	3	3
Total Investment in PATH-WV	$ 24	$ 24	$ 16	$ 16

Accounting for the Effects of Cost-Based Regulation

As the owner of rate-regulated electric public utility companies, our consolidated financial statements reflect the actions of regulators that result in the recognition of certain revenues and expenses in different time periods than enterprises that are not rate-regulated. In accordance with accounting guidance for "Regulated Operations," we record regulatory assets (deferred expenses) and regulatory liabilities (future revenue reductions or refunds) to reflect the economic effects of regulation by matching expenses with their recovery through regulated revenues and income with its passage to customers through the reduction of regulated revenues. Due to the passage of legislation requiring restructuring and a transition to customer choice and market-based rates, we discontinued the application of "Regulated Operations" accounting treatment for the generation portion of our business in Ohio for CSPCo and OPCo and in Texas for TNC. In 2009, the Texas legislature amended its restructuring legislation for the generation portion of SWEPCo's Texas retail jurisdiction to delay indefinitely restructuring requirements. As a result, SWEPCo reapplied accounting guidance for "Regulated Operations" to its Texas generation operations.

Accounting guidance for "Discontinuation of Rate-Regulated Operations" requires the recognition of an impairment of stranded net regulatory assets and stranded plant costs if they are not recoverable in regulated rates. In addition, an enterprise is required to eliminate from its balance sheet the effects of any actions of regulators that had been recognized as regulatory assets and regulatory liabilities. Such impairments and adjustments are classified as an extraordinary item. Consistent with accounting guidance for "Discontinuation of Rate-Regulated Operations," SWEPCo recorded an extraordinary reduction in earnings and shareholder’s equity from the reapplication of “Regulated Operations” accounting guidance in 2009.

Use of Estimates

The preparation of these financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates include, but are not limited to, inventory valuation, allowance for doubtful accounts, goodwill, intangible and long-lived asset impairment, unbilled electricity revenue, valuation of long-term energy contracts, the effects of regulation, long-lived asset recovery, storm costs, the effects of contingencies and certain assumptions made in accounting for pension and postretirement benefits. The estimates and assumptions used are based upon management's evaluation of the relevant facts and circumstances as of the date of the financial statements. Actual results could ultimately differ from those estimates.

Cash and Cash Equivalents

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

Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS and funds held by trustees primarily for the payment of debt.

We classify our investments in marketable securities as available-for-sale or held-to-maturity in accordance with the provisions of "Investments – Debt and Equity Securities" accounting guidance. We do not have any investments classified as trading.

Available-for-sale securities reflected in Other Temporary Investments are carried at fair value with the unrealized gain or loss, net of tax, reported in AOCI. Held-to-maturity securities reflected in Other Temporary Investments are carried at amortized cost. The cost of securities sold is based on the specific identification or weighted average cost method.

In evaluating potential impairment of securities with unrealized losses, we considered, among other criteria, the current fair value compared to cost, the length of time the security's fair value has been below cost, our intent and ability to retain the investment for a period of time sufficient to allow for any anticipated recovery in value and current economic conditions. See "Fair Value Measurements of Other Temporary Investments" in Note 11.

Inventory

Fossil fuel inventories are generally carried at average cost. Materials and supplies inventories are carried at average cost.

Accounts Receivable

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

We recognize revenue from electric power sales when we deliver power to our customers. To the extent that deliveries have occurred but a bill has not been issued, we accrue and recognize, as Accrued Unbilled Revenues on our Consolidated Balance Sheets, an estimate of the revenues for energy delivered since the last billing.

AEP Credit factors accounts receivable on a daily basis, excluding receivables from risk management activities, for CSPCo, I&M, KGPCo, KPCo, OPCo, PSO, SWEPCo and a portion of APCo. Since APCo does not have regulatory authority to sell accounts receivable in its West Virginia regulatory jurisdiction, only a portion of APCo's accounts receivable are sold to AEP Credit. AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the billed and unbilled receivables AEP Credit acquires from affiliated utility subsidiaries. Prior to January 1, 2010, this transaction constituted a sale of receivables in accordance with the accounting guidance for “Transfers and Servicing,” allowing the receivables to be removed from our Consolidated Balance Sheets (see “Securitized

Accounts Receivable – AEP Credit" section of Note 14). See "ASU 2009-16 'Transfers and Servicing' " section of Note 2 for a discussion of the impact of accounting guidance effective January 1, 2010 whereby such future transactions do not constitute a sale of receivables and are accounted for as financings.

Allowance for Uncollectible Accounts

Generally, AEP Credit records bad debt expense based upon a 12-month rolling average of bad debt write-offs in proportion to gross accounts receivable purchased from participating AEP subsidiaries. For receivables related to APCo's West Virginia operations, the bad debt reserve is calculated based on a rolling two-year average write-off in proportion to gross accounts receivable. For customer accounts receivables related to our risk management activities, accounts receivables are reviewed for bad debt reserves at a specific counterparty level basis. For the wires business of TCC and TNC, bad debt reserves are calculated using the specific identification of receivable balances greater than 120 days delinquent. For miscellaneous accounts receivable, bad debt expense is recorded for all amounts outstanding 180 days or greater at 100%, unless specifically identified. Miscellaneous accounts receivable items open less than 180 days may be reserved using specific identification for bad debt reserves.

Emission Allowances

We record emission allowances at cost, including the annual SO_2 and NO_x emission allowance entitlements received at no cost from the Federal EPA. We follow the inventory model for these allowances. We record allowances expected to be consumed within one year in Materials and Supplies and allowances with expected consumption beyond one year in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. We record the consumption of allowances in the production of energy in Fuel and Other Consumables Used for Electric Generation on our Consolidated Statements of Income at an average cost. We record allowances held for speculation in Prepayments and Other Current Assets on our Consolidated Balance Sheets. We report the purchases and sales of allowances in the Operating Activities section of the Statements of Cash Flows. We record the net margin on sales of emission allowances in Utility Operations Revenue on our Consolidated Statements of Income because of its integral nature to the production process of energy and our revenue optimization strategy for our utility operations. The net margin on sales of emission allowances affects the determination of deferred fuel or deferred emission allowance costs and the amortization of regulatory assets for certain jurisdictions.

Property, Plant and Equipment and Equity Investments

Regulated

Electric utility property, plant and equipment for our rate-regulated operations are stated at original purchase cost. Additions, major replacements and betterments are added to the plant accounts. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation under the group composite method of depreciation. The group composite method of depreciation assumes that on average, asset components are retired at the end of their useful lives and thus there is no gain or loss. The equipment in each primary electric plant account is identified as a separate group. Under the group composite method of depreciation, continuous interim routine replacements of items such as boiler tubes, pumps, motors, etc. result in the original cost, less salvage, being charged to accumulated depreciation. The depreciation rates that are established take into account the past history of interim capital replacements and the amount of salvage received. These rates and the related lives are subject to periodic review. Removal costs are charged to regulatory liabilities. The costs of labor, materials and overhead incurred to operate and maintain our plants are included in operating expenses.

Long-lived assets are required to be tested for impairment when it is determined that the carrying value of the assets may no longer be recoverable or when the assets meet the held for sale criteria under the accounting guidance for "Impairment or Disposal of Long-Lived Assets." Equity investments are required to be tested for impairment when it is determined there may be an other-than-temporary loss in value.

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

Nonregulated

Our nonregulated operations generally follow the policies of our cost-based rate-regulated operations listed above but with the following exceptions. Property, plant and equipment of nonregulated operations and equity investments (included in Deferred Charges and Other Noncurrent Assets) are stated at fair value at acquisition (or as adjusted for any applicable impairments) plus the original cost of property acquired or constructed since the acquisition, less disposals. Normal and routine retirements from the plant accounts, net of salvage, are charged to accumulated depreciation for most nonregulated operations under the group composite method of depreciation. For nonregulated plant assets, a gain or loss would be recorded if the retirement is not considered an interim routine replacement. Removal costs are charged to expense.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

AFUDC represents the estimated cost of borrowed and equity funds used to finance construction projects that is capitalized and recovered through depreciation over the service life of regulated electric utility plant. For nonregulated operations, including generating assets in Ohio and certain generating assets in Texas, interest is capitalized during construction in accordance with the accounting guidance for "Capitalization of Interest". We record the equity component of AFUDC in Allowance for Equity Funds Used During Construction and the debt component of AFUDC as a reduction to Interest Expense.

Valuation of Nonderivative Financial Instruments

The book values of Cash and Cash Equivalents, Accounts Receivable, Short-term Debt and Accounts Payable approximate fair value because of the short-term maturity of these instruments. The book value of the pre-April 1983 spent nuclear fuel disposal liability approximates the best estimate of its fair value.

Fair Value Measurements of Assets and Liabilities

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

For our commercial activities, exchange traded derivatives, namely futures contracts, are generally fair valued based on unadjusted quoted prices in active markets and are classified as Level 1. Level 2 inputs primarily consist of OTC broker quotes in moderately active or less active markets, as well as exchange traded contracts where there is insufficient market liquidity to warrant inclusion in Level 1. We verify our price curves using these broker quotes and classify these fair values within Level 2 when substantially all of the fair value can be corroborated. We typically obtain multiple broker quotes, which are non-binding in nature, but are based on recent trades in the marketplace. When multiple broker quotes are obtained, we average the quoted bid and ask prices. In certain circumstances, we may discard a broker quote if it is a clear outlier. We use a historical correlation analysis between the broker quoted location and the illiquid locations and if the points are highly correlated we include these locations within Level 2 as well. Certain OTC and bilaterally executed derivative instruments are executed in less active markets with a lower availability of pricing information. Long-dated and illiquid complex or structured transactions and FTRs can introduce the need for internally developed modeling inputs based upon extrapolations and assumptions of observable market data to estimate fair value. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized as Level 3.

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

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

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

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

Deferred Fuel Costs

The cost of fuel and related emission allowances and emission control chemicals/consumables is charged to Fuel and Other Consumables Used for Electric Generation expense when the fuel is burned or the allowance or consumable is utilized. The cost of fuel also includes the cost of nuclear fuel burned which is computed primarily on the units-of-production method. In regulated jurisdictions with an active FAC, fuel cost over-recoveries (the excess of fuel revenues billed to customers over applicable fuel costs incurred) are generally deferred as current regulatory liabilities and under-recoveries (the excess of applicable fuel costs incurred over fuel revenues billed to customers) are generally deferred as current regulatory assets. These deferrals are amortized when refunded or when billed to customers in later months with the state regulatory commissions' review and approval. The amount of an over-recovery or under-recovery can also be affected by actions of the state regulatory commissions. On a routine basis, state regulatory commissions review and/or audit our fuel procurement policies and practices, the fuel cost calculations and FAC deferrals. When a fuel cost disallowance becomes probable, we adjust our FAC deferrals and record provisions for estimated refunds to recognize these probable outcomes. Fuel cost over-recovery and under-recovery balances are classified as noncurrent when there is a phase-in plan or the FAC has been suspended.

Changes in fuel costs, including purchased power in Kentucky for KPCo, in Indiana and Michigan for I&M, in Texas, Louisiana and Arkansas for SWEPCo, in Oklahoma for PSO and in Virginia and West Virginia (prior to 2009) for APCo are reflected in rates in a timely manner through the FAC. Beginning in 2009, changes in fuel costs, including purchased power in Ohio for CSPCo and OPCo and in West Virginia for APCo are reflected in rates through FAC phase-in plans. All of the profits from off-system sales are given to customers through the FAC in West Virginia for APCo. A portion of profits from off-system sales are shared with customers through the FAC and other rate mechanisms in Oklahoma for PSO, Texas, Louisiana and Arkansas for SWEPCo, Kentucky for KPCo, Virginia for APCo and in Indiana and Michigan (all areas of Michigan beginning in December 2010) for I&M. Where the FAC or off-system sales sharing mechanism is capped, frozen or non-existent (prior to 2009 for CSPCo and OPCo in Ohio and currently in Texas for AEP Energy Partners, Inc.), changes in fuel costs or sharing of off-system sales impacted earnings.

Revenue Recognition

Regulatory Accounting

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

When regulatory assets are probable of recovery through regulated rates, we record them as assets on our Consolidated Balance Sheets. We test for probability of recovery at each balance sheet date or whenever new events occur. Examples of new events include the issuance of a regulatory commission order or passage of new legislation. If it is determined that recovery of a regulatory asset is no longer probable, we write off that regulatory asset as a charge against income.

Traditional Electricity Supply and Delivery Activities

Revenues are recognized from retail and wholesale electricity sales and electricity transmission and distribution delivery services. We recognize the revenues on our Consolidated Statements of Income upon delivery of the energy to the customer and include unbilled as well as billed amounts. In accordance with the applicable state commission regulatory treatment, PSO and SWEPCo do not record the fuel portion of unbilled revenue.

Most of the power produced at the generation plants of the AEP East companies is sold to PJM, the RTO operating in the east service territory. We purchase power from PJM to supply our customers. Generally, these power sales and purchases are reported on a net basis as revenues on our Consolidated Statements of Income. However, purchases of power in excess of sales to PJM, on an hourly net basis, used to serve retail load are recorded gross as Purchased Electricity for Resale on our Consolidated Statements of Income. Other RTOs in which we operate do not function in the same manner as PJM. They function as balancing organizations and not as exchanges.

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

In general, we record expenses when purchased electricity is received and when expenses are incurred, with the exception of certain power purchase contracts that are derivatives and accounted for using MTM accounting where generation/supply rates are not cost-based regulated. In jurisdictions where the generation/supply business is subject to cost-based regulation, the unrealized MTM amounts are deferred as regulatory assets (for losses) and regulatory liabilities (for gains).

Energy Marketing and Risk Management Activities

We engage in wholesale electricity, natural gas, coal and emission allowances marketing and risk management activities focused on wholesale markets where we own assets and on adjacent markets. Our activities include the purchase and sale of energy under forward contracts at fixed and variable prices and the buying and selling of financial energy contracts, which include exchange traded futures and options, as well as over-the-counter options and swaps. We engage in certain energy marketing and risk management transactions with RTOs.

We recognize revenues and expenses from wholesale marketing and risk management transactions that are not derivatives upon delivery of the commodity. We use MTM accounting for wholesale marketing and risk management transactions that are derivatives unless the derivative is designated in a qualifying cash flow hedge relationship or a normal purchase or sale. We include the unrealized and realized gains and losses on wholesale marketing and risk management transactions that are accounted for using MTM in Revenues on our Consolidated Statements of Income on a net basis. In jurisdictions subject to cost-based regulation, we defer the unrealized MTM amounts and some realized gains and losses as regulatory assets (for losses) and regulatory liabilities (for gains). We include unrealized MTM gains and losses resulting from derivative contracts on our Consolidated Balance Sheets as Risk Management Assets or Liabilities as appropriate.

Certain qualifying wholesale marketing and risk management derivative transactions are designated as hedges of variability in future cash flows as a result of forecasted transactions (cash flow hedge). We initially record the effective portion of the cash flow hedge's gain or loss as a component of AOCI. When the forecasted transaction is realized and affects net income, we subsequently reclassify the gain or loss on the hedge from AOCI into revenues or expenses within the same financial statement line item as the forecasted transaction on our Consolidated Statements of Income. Excluding those jurisdictions subject to cost-based regulation, we recognize the ineffective portion of the gain or loss in revenues or expense immediately on our Consolidated Statements of Income, depending on the specific nature of the associated hedged risk. In regulated jurisdictions, we defer the ineffective portion as regulatory assets (for losses) and regulatory liabilities (for gains) (see "Accounting for Cash Flow Hedging Strategies" section of Note 10).

Barging Activities

AEP River Operations' revenue is recognized based on percentage of voyage completion. The proportion of freight transportation revenue to be recognized is determined by applying a percentage to the contractual charges for such services. The percentage is determined by dividing the number of miles from the loading point to the position of the barge as of the end of the accounting period by the total miles to the destination specified in the customer's freight contract. The position of the barge at accounting period end is determined by our computerized barge tracking system.

Levelization of Nuclear Refueling Outage Costs

In order to match costs with nuclear refueling cycles, I&M defers incremental operation and maintenance costs associated with periodic refueling outages at its Cook Plant and amortizes the costs over the period beginning with the month following the start of each unit's refueling outage and lasting until the end of the month in which the same unit's next scheduled refueling outage begins. I&M adjusts the amortization amount as necessary to ensure full amortization of all deferred costs by the end of the refueling cycle.

Maintenance

We expense maintenance costs as incurred. If it becomes probable that we will recover specifically-incurred costs through future rates, we establish a regulatory asset to match the expensing of those maintenance costs with their recovery in cost-based regulated revenues. We defer distribution tree trimming costs for PSO above the level included in base rates and amortize those deferrals commensurate with recovery through a rate rider in Oklahoma.

Income Taxes and Investment Tax Credits

We use the liability method of accounting for income taxes. Under the liability method, we provide deferred income taxes for all temporary differences between the book and tax basis of assets and liabilities which will result in a future tax consequence.

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

We account for investment tax credits under the flow-through method except where regulatory commissions reflect investment tax credits in the rate-making process on a deferral basis. We amortize deferred investment tax credits over the life of the plant investment.

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

Excise Taxes

We act as an agent for some state and local governments and collect from customers certain excise taxes levied by those state or local governments on our customers. We do not recognize these taxes as revenue or expense.

Government Grants

In 2010, APCo received final approval for a federal stimulus grant for a commercial scale Carbon Capture and Sequestration facility under consideration at the Mountaineer Plant. Also in 2010, CSPCo received final approval for a federal stimulus grant for the gridSMART® demonstration program. For each project, APCo and CSPCo are reimbursed by the Department of Energy for allowable costs incurred during the billing period. These reimbursements result in the reduction of Other Operation and Maintenance expenses on our Consolidated Statements of Income or a reduction in Construction Work in Progress on our Consolidated Balance Sheets.

Debt and Preferred Stock

We defer gains and losses from the reacquisition of debt used to finance regulated electric utility plants and amortize the deferral over the remaining term of the reacquired debt in accordance with their rate-making treatment unless the debt is refinanced. If we refinance the reacquired debt associated with the regulated business, the reacquisition costs attributable to the portions of the business subject to cost-based regulatory accounting are generally deferred and amortized over the term of the replacement debt consistent with its recovery in rates. Some jurisdictions require that these costs be expensed upon reacquisition. We report gains and losses on the reacquisition of debt for operations not subject to cost-based rate regulation in Interest Expense on our Consolidated Statements of Income.

We defer debt discount or premium and debt issuance expenses and amortize generally utilizing the straight-line method over the term of the related debt. The straight-line method approximates the effective interest method and is consistent with the treatment in rates for regulated operations. We include the amortization expense in Interest Expense on our Consolidated Statements of Income.

Where reflected in rates, we include redemption premiums paid to reacquire preferred stock of utility subsidiaries in paid-in capital and amortize the premiums to retained earnings commensurate with recovery in rates. We credit the excess of par value over costs of preferred stock reacquired to paid-in capital and reclassify the excess to retained earnings upon the redemption of the entire preferred stock series.

Goodwill and Intangible Assets

When we acquire businesses, we record the fair value of all assets and liabilities, including intangible assets. To the extent that consideration exceeds the fair value of identified assets, we record goodwill. We do not amortize goodwill and intangible assets with indefinite lives. We test acquired goodwill and other intangible assets with indefinite lives for impairment at least annually at their estimated fair value. We test goodwill at the reporting unit level and other intangibles at the asset level. Fair value is the amount at which an asset or liability could be bought or sold in a current transaction between willing parties, that is, other than in a forced or liquidation sale. Quoted market prices in active markets are the best evidence of fair value and are used as the basis for the measurement, if available. In the absence of quoted prices for identical or similar assets in active markets, we estimate fair value using various internal and external valuation methods. We amortize intangible assets with finite lives over their respective estimated lives, currently 10 years, to their estimated residual values. We also review the lives of the amortizable intangibles with finite lives on an annual basis.

Investments Held in Trust for Future Liabilities

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

Benefit Plans

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

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

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

The target asset allocation and allocation ranges are as follows:

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

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

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

For equity investments, the limits are as follows:

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

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

- 3% in one issuer
- 20% in non-US dollar denominated
- 5% private placements
- 5% convertible securities

- 60% for bonds rated AA+ or lower
- 50% for bonds rated A+ or lower
- 10% for bonds rated BBB- or lower

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

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

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

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

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

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

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

Nuclear Trust Funds

Nuclear decommissioning and spent nuclear fuel trust funds represent funds that regulatory commissions allow us to collect through rates to fund future decommissioning and spent nuclear fuel disposal liabilities. By rules or orders, the IURC, the MPSC and the FERC established investment limitations and general risk management guidelines. In general, limitations include:

- Acceptable investments (rated investment grade or above when purchased).
- Maximum percentage invested in a specific type of investment.
- Prohibition of investment in obligations of AEP or its affiliates.
- Withdrawals permitted only for payment of decommissioning costs and trust expenses.

We maintain trust records for each regulatory jurisdiction. The trust assets may not be used for another jurisdiction's liabilities. Regulatory approval is required to withdraw decommissioning funds. These funds are managed by external investment managers who must comply with the guidelines and rules of the applicable regulatory authorities. The trust assets are invested to optimize the net of tax earnings of the trust giving consideration to liquidity, risk, diversification and other prudent investment objectives.

We record securities held in these trust funds as Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets. We record these securities at fair value. We classify securities in the trust funds as available-for-sale due to their long-term purpose. Other-than-temporary impairments for investments in both debt and equity securities are considered realized losses as a result of securities being managed by an external investment management firm. The external investment management firm makes specific investment decisions regarding the equity and debt investments held in these trusts and generally intends to sell debt securities in an unrealized loss position as part of a tax optimization strategy. Impairments reduce the cost basis of the securities which will affect any future unrealized gain or realized gain or loss due to the adjusted cost of investment. We record unrealized gains and other-than-temporary impairments from securities in these trust funds as adjustments to the regulatory liability account for the nuclear decommissioning trust funds and to regulatory assets or liabilities for the spent nuclear fuel disposal trust funds in accordance with their treatment in rates. Consequently, changes in fair value of trust assets do not affect earnings or AOCI. See the "Nuclear Contingencies" section of Note 6 for additional discussion of nuclear matters. See "Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal" section of Note 11 for disclosure of the fair value of assets within the trusts.

Comprehensive Income (Loss)

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

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

AOCI is included on our Consolidated Balance Sheets in our equity section. Our components of AOCI as of December 31, 2010 and 2009 are shown in the following table:

Components	December 31, 2010	December 31, 2009
	(in millions)	
Securities Available for Sale, Net of Tax	$ 4	$ 12
Cash Flow Hedges, Net of Tax	11	(15)
Amortization of Pension and OPEB Deferred Costs, Net of Tax	57	35
Pension and OPEB Funded Status, Net of Tax	(453)	(406)
Total	$ (381)	$ (374)

Stock-Based Compensation Plans

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

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

We compensate our non-employee directors, in part, with stock units under the American Electric Power Company, Inc. Stock Unit Accumulation Plan for Non-Employee Directors. These stock units become payable in cash to directors after their service ends.

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

We recognize compensation expense for all share-based awards with service only vesting conditions granted on or after January 2006 using the straight-line single-option method. Stock-based compensation expense recognized on our Consolidated Statements of Income for the years ended December 31, 2010, 2009 and 2008 is based on awards ultimately expected to vest. Therefore, stock-based compensation expense has been reduced to reflect estimated forfeitures. Accounting guidance for "Compensation - Stock Compensation" requires forfeitures to be estimated at the time of grant and revised, if necessary, in subsequent periods if actual forfeitures differ from those estimates.

For the years ended December 31, 2010, 2009 and 2008, compensation expense is included in Net Income for the performance units, career shares, restricted shares, restricted stock units and the non-employee director's stock units. See Note 15 for additional discussion.

Earnings Per Share (EPS)

Shown below are income statement amounts attributable to AEP common shareholders:

	Years Ended December 31,		
Amounts Attributable to AEP Common Shareholders	**2010**	**2009**	**2008**
		(in millions)	
Income Before Discontinued Operations and Extraordinary Loss	$ 1,211	$ 1,362	$ 1,368
Discontinued Operations, Net of Tax	-	-	12
Extraordinary Loss, Net of Tax	-	(5)	-
Net Income	$ 1,211	$ 1,357	$ 1,380

Basic earnings per common share is calculated by dividing net earnings available to common shareholders by the weighted average number of common shares outstanding during the period. Diluted earnings per common share is calculated by adjusting the weighted average outstanding common shares, assuming conversion of all potentially dilutive stock options and awards.

The following table presents our basic and diluted EPS calculations included on our Consolidated Statements of Income:

	Years Ended December 31,					
	2010		**2009**		**2008**	
	(in millions, except per share data)					
		$/share		**$/share**		**$/share**
Earnings Attributable to AEP Common Shareholders	$ 1,211		$ 1,357		$ 1,380	
Weighted Average Number of Basic Shares Outstanding	479.4	$ 2.53	458.7	$ 2.96	402.1	$ 3.43
Weighted Average Dilutive Effect of:						
Performance Share Units	0.1	-	0.3	-	1.2	0.01

Stock Options	-	-	-	-	0.1	-
Restricted Stock Units	0.1	-	-	-	0.1	-
Restricted Shares	-	-	-	-	0.1	-
Weighted Average Number of Diluted Shares Outstanding	479.6	$ 2.53	459.0	$ 2.96	403.6	$ 3.42

The assumed conversion of stock options does not affect net earnings for purposes of calculating diluted earnings per share.

Options to purchase 136,250, 452,216 and 470,016 shares of common stock were outstanding at December 31, 2010, 2009 and 2008, respectively, but were not included in the computation of diluted earnings per share attributable to AEP common shareholders. Since the options' exercise prices were greater than the average market price of the common shares, the effect would have been antidilutive.

CSPCo and OPCo Revised Depreciation Rates

Effective January 1, 2009, we revised book depreciation rates for CSPCo and OPCo generating plants consistent with a completed depreciation study. OPCo's overall higher depreciation rates primarily related to shortened depreciable lives for certain OPCo generating facilities. In comparing 2009 and 2008, the change in depreciation rates resulted in a net increase (decrease) in depreciation expense of:

	Depreciation Expense Variance
	Years Ended December 31, 2009/2008
	(in millions)
CSPCo	$ (18)
OPCo	71

The net change in depreciation rates resulted in a decrease to our net-of-tax, basic earnings per share of $0.08 for the year ended December 31, 2009.

Supplementary Information

Related Party Transactions	Years Ended December 31, 2010	2009	2008
		(in millions)	
AEP Consolidated Revenues – Utility Operations:			
Ohio Valley Electric Corporation (43.47% owned)	$ (20)(a)	$ -	$ (54)(b)
AEP Consolidated Revenues – Other Revenues:			
Ohio Valley Electric Corporation – Barging and Other Transportation Services (43.47% Owned)	29	31	32
AEP Consolidated Expenses – Purchased Electricity for Resale:			
Ohio Valley Electric Corporation (43.47% Owned)	302 (c)	286	263

(a) The AEP Power Pool purchased power from OVEC to serve off-system sales in an agreement that began in January 2010 and ended in June 2010.

(b) The AEP Power Pool purchased power from OVEC as part of risk management activities in an agreement that ended in December 2008.

(c) The AEP Power Pool purchased power from OVEC to serve retail sales in an agreement that began in January 2010 and ended in June 2010. The total amount reported in 2010 includes $10 million related to this agreement.

Cash Flow Information	Years Ended December 31, 2010	2009	2008
		(in millions)	
Cash Paid (Received) for:			
Interest, Net of Capitalized Amounts	$ 958	$ 924	$ 853
Income Taxes	(268)	(98)	233
Noncash Investing and Financing Activities:			
Acquisitions Under Capital Leases	225	86	62
Assumption of Liabilities Related to Acquisitions	8	-	-
Government Grants Included in Accounts Receivable at December 31,	10	-	-
Construction Expenditures Included in Accounts Payable at December 31,	267	348	460
Acquisition of Nuclear Fuel Included in Accounts Payable at December 31,	-	-	38
Noncash Donation Expense Related to Issuance of Treasury Shares to AEP Foundation	-	-	40

Transmission Investments

We participate in certain joint ventures which involve the development, construction, ownership and operation of transmission facilities. These investments are recorded using the equity method and reported as Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets.

Adjustments to Securitized Accounts Receivable Disclosure

In the "Securitized Accounts Receivable – AEP Credit" section of Note 14, we expanded our disclosure to reflect certain prior period amounts related to our securitization agreement that were not previously disclosed. These omissions were not material to our financial statements and had no impact on our previously reported net income, changes in shareholders' equity, financial position or cash flows.

2. NEW ACCOUNTING PRONOUNCEMENTS AND EXTRAORDINARY ITEM

NEW ACCOUNTING PRONOUNCEMENTS

Upon issuance of final pronouncements, we review the new accounting literature to determine its relevance, if any, to our business. The following represents a summary of final pronouncements that impact our financial statements.

Pronouncements Adopted During 2010

The following standards were effective during 2010. Consequently, their impact is reflected in the financial statements. The following paragraphs discuss their impact.

ASU 2009-16 "Transfers and Servicing" (ASU 2009-16)

In 2009, the FASB issued ASU 2009-16 clarifying when a transfer of a financial asset should be recorded as a sale. The standard defines participating interest to establish specific conditions for a sale of a portion of a financial asset. This standard must be applied to all transfers after the effective date.

We adopted ASU 2009-16 effective January 1, 2010. AEP Credit securitizes an interest in receivables it acquires from certain of its affiliates to bank conduits and receives cash. As of December 31, 2009, AEP Credit owed $656 million to bank conduits related to receivable sales outstanding. Upon adoption of ASU 2009-16, future transactions do not constitute a sale of receivables and are accounted for as financings. Effective January 2010, we record the receivables and related debt on our Consolidated Balance Sheet.

ASU 2009-17 "Consolidations" (ASU 2009-17)

In 2009, the FASB issued ASU 2009-17 amending the analysis an entity must perform to determine if it has a controlling financial interest in a VIE. In addition to presentation and disclosure guidance, ASU 2009-17 provides that the primary beneficiary of a VIE must have both:

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

We adopted the prospective provisions of ASU 2009-17 effective January 1, 2010 and deconsolidated DHLC. DHLC was deconsolidated due to the shared control between SWEPCo and CLECO. After January 1, 2010, we report DHLC using the equity method of accounting.

This standard increased our disclosure requirements for AEP Credit and Transition Funding, wholly-owned consolidated subsidiaries. See "Variable Interest Entities" section of Note 1 for further discussion.

EXTRAORDINARY ITEM

SWEPCo Texas Restructuring

In August 2006, the PUCT adopted a rule extending the delay in implementation of customer choice in SWEPCo's SPP area of Texas until no sooner than January 1, 2011. In May 2009, the governor of Texas signed a bill related to SWEPCo's SPP area of Texas that requires continued cost of service regulation until certain stages have been completed and approved by the PUCT such that fair competition is available to all Texas retail customer classes. Based upon the signing of the bill, SWEPCo re-applied "Regulated Operations" accounting guidance for the generation portion of SWEPCo's Texas retail jurisdiction effective second quarter of 2009. Management believes that a return to competition in the SPP area of Texas will not occur. The reapplication of "Regulated Operations" accounting guidance resulted in an $8 million ($5 million, net of tax) extraordinary loss.

3. GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

The changes in our carrying amount of goodwill for the years ended December 31, 2010 and 2009 by operating segment are as follows:

	Utility Operations	AEP River Operations	AEP Consolidated
		(in millions)	
Balance at December 31, 2008	$ 37	$ 39	$ 76
Impairment Losses	-	-	-
Balance at December 31, 2009	37	39	76
Impairment Losses	-	-	-
Balance at December 31, 2010	$ 37	$ 39	$ 76

In the fourth quarters of 2010 and 2009, we performed our annual impairment tests. The fair values of the operations with goodwill were estimated using cash flow projections and other market value indicators. There were no goodwill impairment losses. We do not have any accumulated impairment on existing goodwill.

Other Intangible Assets

Acquired intangible assets subject to amortization were $1.2 million and $10.3 million at December 31, 2010 and 2009, respectively, net of accumulated amortization and are included in Deferred Charges and Other Noncurrent Assets on our Consolidated Balance Sheets. The amortization life, gross carrying amount and accumulated amortization by major asset class are as follows:

		December 31,							
		2010				2009			
	Amortization Life	**Gross Carrying Amount**		**Accumulated Amortization**		**Gross Carrying Amount**		**Accumulated Amortization**	
	(in years)	**(in millions)**							
Easements	10	$	2.2	$	2.2	$	2.2	$	1.9
Purchased Technology	10		10.9		9.7		10.9		8.6
Advanced Royalties	15		-		-		29.4		21.7
Total		$	13.1	$	11.9	$	42.5	$	32.2

Amortization of intangible assets was $ 1 million, $3 million and $3 million for 2010, 2009 and 2008, respectively. Our estimated total amortization is $1 million for 2011 and $138 thousand for 2012.

The Advanced Royalties asset class relates to the lignite mine of DHLC, a wholly-owned subsidiary of SWEPCo. As of January 1, 2010, SWEPCo no longer consolidates DHLC, but rather it is reported as an equity investment, resulting in the elimination of a review of this asset by SWEPCo. Also, see “ASU 2009-17 ‘Consolidations’” section of Note 2 for discussion of impact of new accounting guidance effective January 1, 2010.

Other than goodwill, we have no intangible assets that are not subject to amortization.

4. RATE MATTERS

Our subsidiaries are involved in rate and regulatory proceedings at the FERC and their state commissions. Rate matters can have a material impact on net income, cash flows and possibly financial condition. Our recent significant rate orders and pending rate filings are addressed in this note.

CSPCo and OPCo Rate Matters

Ohio Electric Security Plan Filings

2009 – 2011 ESPs

The PUCO issued an order in March 2009 that modified and approved CSPCo’s and OPCo’s ESPs which established rates at the start of the April 2009 billing cycle. The ESPs are in effect through 2011. The order also limited annual rate increases for CSPCo to 7% in 2009, 6% in 2010 and 6% in 2011 and for OPCo to 8% in 2009, 7% in 2010 and 8% in 2011. Some rate components and increases are exempt from these limitations. CSPCo and OPCo collected the 2009 annualized revenue increase over the last nine months of 2009.

The order provided a FAC for the three-year period of the ESP. The FAC was phased in to avoid having the resultant rate increases exceed the ordered annual caps described above. The FAC is subject to quarterly true-ups, annual accounting audits and prudency reviews. See the “2009 Fuel Adjustment Clause Audit” section below. The order allowed CSPCo and OPCo to defer any unrecovered FAC costs resulting from the annual caps and accrued associated carrying charges at CSPCo’s and OPCo’s weighted average cost of capital. Any deferred FAC regulatory asset balance at the end of the three-year ESP period will be recovered through a non-bypassable surcharge over the period 2012 through 2018. That recovery will include 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. See the "Ormet Interim Arrangement" section below. The FAC deferral as of December 31, 2010 was $ 476 million for OPCo excluding $30 million of unrecognized equity carrying costs.

Discussed below are the significant outstanding uncertainties related to the ESP order:

The Ohio Consumers' Counsel filed a notice of appeal with the Supreme Court of Ohio raising several issues including alleged retroactive ratemaking, recovery of carrying charges on certain environmental investments, Provider of Last Resort (POLR) charges and the decision not to offset rates by off-system sales margins. A decision from the Supreme Court of Ohio is pending.

In November 2009, the Industrial Energy Users-Ohio filed a notice of appeal with the Supreme Court of Ohio challenging components of the ESP order including the POLR charge, the distribution riders for gridSMART® and enhanced reliability, the PUCO's conclusion and supporting evaluation that the modified ESPs are more favorable than the expected results of a market rate offer, the unbundling of the fuel and non-fuel generation rate components, the scope and design of the fuel adjustment clause and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

In April 2010, the Industrial Energy Users-Ohio filed an additional notice of appeal with the Supreme Court of Ohio challenging alleged retroactive ratemaking, CSPCo's and OPCo's abilities to collect through the FAC amounts deferred under the Ormet interim arrangement and the approval of the plan after the 150-day statutory deadline. A decision from the Supreme Court of Ohio is pending.

Ohio law requires that the PUCO determine, following the end of each year of the ESP, if rate adjustments included in the ESP resulted in significantly excessive earnings under the Significantly Excessive Earnings Test (SEET). If the rate adjustments, in the aggregate, result in significantly excessive earnings, the excess amount could be returned to customers. In September 2010, CSPCo and OPCo filed their 2009 SEET filings with the PUCO. CSPCo's and OPCo's returns on common equity were 20.84% and 10.81%, respectively, including off-system sales margins. In January 2011, the PUCO issued an order that determined a return on common equity for 2009 in excess of 17.6% would be significantly excessive. The PUCO determined that OPCo's 2009 earnings were not significantly excessive but determined relevant CSPCo earnings, excluding off-system sales margins, to be 19.73%, which exceeded the PUCO determined threshold by 2.13%. As a result, the PUCO ordered CSPCo to refund $43 million ($ 28 million net of tax) of its earnings to customers, which was recorded as a revenue provision on CSPCo's December 2010 books. The PUCO ordered that the significantly excessive earnings be applied first to CSPCo's FAC deferral, including unrecognized equity carrying costs, as of the date of the order, with any remaining balance to be credited to CSPCo's customers on a per kilowatt basis which began with the first billing cycle in February 2011 through December 2011. Several parties, including CSPCo and OPCo, have filed requests for rehearing with the PUCO, which remain pending. CSPCo and OPCo are required to file their 2010 SEET filing with the PUCO in 2011. Based upon the approach in the PUCO 2009 order, management does not currently believe that there are significantly excessive earnings in 2010.

Management is unable to predict the outcome of the various ongoing ESP proceedings and litigation discussed above. If these proceedings, including future SEET filings, result in adverse rulings, it could reduce future net income and cash flows and impact financial condition.

Proposed January 2012 – May 2014 ESP

In January 2011, CSPCo and OPCo filed an application with the PUCO to approve a new ESP that includes a standard service offer (SSO) pricing on a combined company basis for generation effective with the first billing cycle of January 2012 through the last billing cycle of May 2014. The ESP also includes alternative energy resource requirements and addresses provisions regarding distribution service, energy efficiency requirements, economic development, job retention in Ohio and other matters. The SSO presents redesigned generation rates by customer class. Customer class rates individually vary, but on average, customers will experience net base generation increases of 1.4% in 2012 and 2.7% for the period January 2013 through May 2014.

Proposed CSPCo and OPCo Merger

In October 2010, CSPCo and OPCo filed an application with the PUCO to merge CSPCo into OPCo. Approval of the merger will not affect CSPCo's and OPCo's rates until such time as the PUCO approves new rates, terms and conditions for the merged company. In January 2011, CSPCo and OPCo filed an application with the FERC requesting approval for an internal corporate reorganization under which CSPCo will merge into OPCo. CSPCo and OPCo requested the reorganization transaction be effective in October 2011. Decisions are pending from the PUCO and the FERC.

Requested Sporn Unit 5 Shutdown and Proposed Distribution Rider

In October 2010, OPCo filed an application with the PUCO for the approval of a December 2010 closure of Sporn Unit 5 and the simultaneous establishment of a new non-bypassable distribution rider, outside the rate caps established in the 2009 – 2011 ESP proceeding. The proposed rider would recover the net book value of the unit as well as related materials and supplies as of December 2010, which is estimated to be $ 59 million, as well as future closure costs incurred after December 2010. OPCo also requested authority to record the future closure costs as a regulatory asset or regulatory liability with a weighted average cost of capital carrying charge to be included in the proposed non-bypassable distribution rider after they are incurred. Also in October 2010, OPCo filed a retirement notification with PJM pending PUCO approval of OPCo's application to close Sporn Unit 5, which was granted by PJM. Pending PUCO approval, Sporn Unit 5 continues to operate. Management is unable to predict the outcome of this proceeding.

2009 Fuel Adjustment Clause Audit

As required under the ESP orders, the PUCO selected an outside consultant to conduct the audit of the FAC for the period of January 2009 through December 2009. In May 2010, the outside consultant provided their confidential audit report to the PUCO. The audit report included a recommendation that the PUCO should review whether any proceeds from a 2008 coal contract settlement agreement which totaled $72 million should reduce OPCo's FAC under-recovery balance. Of the total proceeds, approximately $58 million was recognized as a reduction to fuel expense prior to 2009 and $14 million reduced fuel expense in 2009 and 2010. Hearings were held in August 2010. If the PUCO orders any portion of the $58 million previously recognized or potential other future adjustments be used to reduce the current year FAC deferral, it would reduce future net income and cash flows and impact financial condition.

Ormet Interim Arrangement

CSPCo, OPCo and Ormet, a large aluminum company, filed an application with the PUCO for approval of an interim arrangement governing the provision of generation service to Ormet. This interim arrangement was approved by the PUCO and was effective from January 2009 through September 2009. In March 2009, the PUCO approved a FAC in the ESP filings. The approval of the FAC, together with the PUCO approval of the interim arrangement, provided the basis to record regulatory assets for the difference between the approved market price and the rate paid by Ormet. The Industrial Energy Users-Ohio, CSPCo and OPCo filed Notices of Appeal regarding aspects of this decision with the Supreme Court of Ohio. A hearing at the Supreme Court of Ohio was held in February 2011. Through September 2009, the last month of the interim arrangement, CSPCo and OPCo had $ 30 million and $34 million, respectively, of deferred FAC related to the interim arrangement including recognized carrying charges. These amounts exclude $ 1 million and $1 million, respectively, of unrecognized equity carrying costs. In November 2009, CSPCo and OPCo requested that the PUCO approve recovery of the deferrals under the interim agreement plus a weighted average cost of capital carrying charge. The interim arrangement deferrals are included in CSPCo's and OPCo's FAC phase-in deferral balances. See "Ohio Electric Security Plan Filings" section above. In the ESP proceeding, intervenors requested that CSPCo and OPCo be required to refund the Ormet-related regulatory assets and requested that the PUCO prevent CSPCo and OPCo from collecting the Ormet-related revenues in the future. The PUCO did not take any action on this request in the ESP proceeding. The intervenors raised the issue again in response to CSPCo's and OPCo's November 2009 filing to approve recovery of the deferrals under the interim agreement. If CSPCo and OPCo are not ultimately permitted to fully recover their requested deferrals under the interim arrangement, it would reduce future net income and cash flows and impact financial condition.

Economic Development Rider

In April 2010, the Industrial Energy Users-Ohio filed a notice of appeal of the 2009 PUCO-approved Economic Development Rider (EDR) with the Supreme Court of Ohio. The EDR collects from ratepayers the difference between the standard tariff and lower contract billings to qualifying industrial customers, subject to PUCO approval. The Industrial Energy Users-Ohio raised several issues including claims that (a) the PUCO lost jurisdiction over CSPCo's and OPCo's ESP proceedings and related proceedings when the PUCO failed to issue ESP orders within the 150-day statutory deadline, (b) the EDR should not be exempt from the ESP annual rate limitations and (c) CSPCo and OPCo should not be allowed to apply a weighted average long-term debt carrying cost on deferred EDR regulatory assets.

In June 2010, Industrial Energy Users-Ohio filed a notice of appeal of the 2010 PUCO-approved EDR with the Supreme Court of Ohio. The Industrial Energy Users-Ohio raised the same issues as noted in the 2009 EDR appeal plus a claim that CSPCo and OPCo should not be able to take the benefits of the higher ESP rates while simultaneously challenging the ESP orders.

As of December 31, 2010, CSPCo and OPCo have incurred $ 38 million and $30 million, respectively, in EDR costs including carrying costs. Of these costs, CSPCo and OPCo have collected $ 35 million and $26 million, respectively, through the EDR, which CSPCo and OPCo began collecting in January 2010. The remaining $ 3 million and $4 million for CSPCo and OPCo, respectively, are recorded as EDR regulatory assets. If CSPCo and OPCo are not ultimately permitted to recover their deferrals or are required to refund revenue collected, it would reduce future net income and cash flows and impact financial condition.

Environmental Investment Carrying Cost Rider

In February 2010, CSPCo and OPCo filed an application with the PUCO to establish an Environmental Investment Carrying Cost Rider to recover carrying costs for 2009 through 2011 related to environmental investments made in 2009. The carrying costs include both a return of and on the environmental investments as well as related administrative and general expenses and taxes. In August 2010, the PUCO issued an order approving a rider of approximately $26 million and $34 million for CSPCo and OPCo, respectively, effective September 2010. The implementation of the rider will likely not impact cash flows since this rider is subject to the rate increase caps authorized by the PUCO in the ESP proceedings, but will increase the ESP phase-in plan deferrals associated with the FAC.

Ohio IGCC Plant

In March 2005, CSPCo and OPCo filed a joint application with the PUCO seeking authority to recover costs of building and operating an IGCC power plant. Through December 31, 2010, CSPCo and OPCo have each collected $12 million in pre-construction costs authorized in a June 2006 PUCO order and each incurred $11 million in pre-construction costs. As a result, CSPCo and OPCo each established a net regulatory liability of approximately $ 1 million. The order also provided that if CSPCo and OPCo have not commenced a continuous course of construction of the proposed IGCC plant before June 2011, all pre-construction costs that may be utilized in projects at other sites must be refunded to Ohio ratepayers with interest. Intervenors have filed motions with the PUCO requesting all pre-construction costs be refunded to Ohio ratepayers with interest.

CSPCo and OPCo will not start construction of an IGCC plant until existing statutory barriers are addressed and sufficient assurance of regulatory cost recovery exists. Management cannot predict the outcome of any cost recovery litigation concerning the Ohio IGCC plant or what effect, if any, such litigation would have on future net income and cash flows. However, if CSPCo and OPCo were required to refund all or some of the pre-construction costs collected and the costs incurred were not recoverable in another jurisdiction, it would reduce future net income and cash flows and impact financial condition.

SWEPCo Rate Matters

Turk Plant

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 2012. SWEPCo owns 73% (440 MW) of the Turk Plant and will operate the completed facility. The Turk Plant is currently estimated to cost $1.7 billion, excluding AFUDC, plus an additional $125 million for transmission, excluding AFUDC. SWEPCo's share is currently estimated to cost $1.3 billion, excluding AFUDC, plus the additional $ 125 million for transmission, excluding AFUDC. As of December 31, 2010, excluding costs attributable to its joint owners, SWEPCo has capitalized approximately $1 billion of expenditures (including AFUDC and capitalized interest of $ 137 million and related transmission costs of

$66 million). As of December 31, 2010, the joint owners and SWEPCo have contractual construction commitments of approximately $321 million (including related transmission costs of $3 million). SWEPCo's share of the contractual construction commitments is $235 million. If the plant is cancelled, the joint owners and SWEPCo would incur contractual construction cancellation fees, based on construction status as of December 31, 2010, of approximately $121 million (including related transmission cancellation fees of $ 1 million). SWEPCo's share of the contractual construction cancellation fees would be approximately $89 million.

Discussed below are the significant outstanding uncertainties related to the Turk Plant:

The APSC granted approval for SWEPCo to build the Turk Plant by issuing a Certificate of Environmental Compatibility and Public Need (CECPN) for the 88 MW SWEPCo Arkansas jurisdictional share of the Turk Plant. Following an appeal by certain intervenors, the Arkansas Supreme Court issued a decision that reversed the APSC's grant of the CECPN. The Arkansas Supreme Court ultimately concluded that the APSC erred in determining the need for additional power supply resources in a proceeding separate from the proceeding in which the APSC granted the CECPN. However, the Arkansas Supreme Court approved the APSC's procedure of granting CECPNs for transmission facilities in dockets separate from the Turk Plant CECPN proceeding. SWEPCo filed a notice with the APSC of its intent to proceed with construction of the Turk Plant but that SWEPCo no longer intends to pursue a CECPN to seek recovery of the originally approved 88 MW portion of Turk Plant costs in Arkansas retail rates. In June 2010, the APSC issued an order which reversed and set aside the previously granted CECPN.

The PUCT issued an order approving a Certificate of Convenience and Necessity (CCN) for the Turk Plant with the following conditions: (a) a cap on the recovery of jurisdictional capital costs for the Turk Plant based on the previously estimated \$ 1.522 billion projected construction cost, excluding AFUDC and related transmission costs, (b) a cap on recovery of annual CO_2 emission costs at \$28 per ton through the year 2030 and (c) a requirement to hold Texas ratepayers financially harmless from any adverse impact related to the Turk Plant not being fully subscribed to by other utilities or wholesale customers. SWEPCo appealed the PUCT's order contending the two cost cap restrictions are unlawful. The Texas Industrial Energy Consumers filed an appeal contending that the PUCT's grant of a conditional CCN for the Turk Plant was unnecessary to serve retail customers. In February 2010, the Texas District Court affirmed the PUCT's order in all respects. In March 2010, SWEPCo and the Texas Industrial Energy Consumers appealed this decision to the Texas Court of Appeals.

The LPSC approved SWEPCo's application to construct the Turk Plant. The Sierra Club filed a complaint with the LPSC to begin an investigation into the construction of the Turk Plant. In November 2010, the LPSC dismissed the complaint.

In November 2008, SWEPCo received its required air permit approval from the Arkansas Department of Environmental Quality and commenced construction at the site. The Arkansas Pollution Control and Ecology Commission (APCEC) upheld the air permit. The parties who unsuccessfully appealed the air permit to the APCEC filed a notice of appeal with the Circuit Court of Hempstead County, Arkansas. In December 2010, the Circuit Court affirmed the APCEC. In January 2011, the same parties asked the Arkansas Court of Appeals to overturn the Circuit Court's December 2010 decision. A decision from the Arkansas Court of Appeals is pending.

A wetlands permit was issued by the U.S. Army Corps of Engineers in December 2009. In 2010, the Sierra Club, the Audubon Society and others filed a complaint in the Federal District Court for the Western District of Arkansas against the U.S. Army Corps of Engineers challenging the process used and the terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts, and sought a preliminary injunction to halt construction and for a temporary restraining order. In July 2010, the Hempstead County Hunting Club also filed a complaint with the Federal District Court for the Western District of Arkansas against SWEPCo, the U.S. Army Corps of Engineers, the U.S. Department of the Interior and the U.S. Fish and Wildlife Service seeking a temporary restraining order and preliminary injunction to stop construction of the Turk Plant asserting claims of violations of federal and state laws. The plaintiffs' federal law claims challenge the process used and terms of the permit issued to SWEPCo authorizing certain wetland and stream impacts. The plaintiffs' state law claims challenge SWEPCo's ability to construct the Turk Plant without obtaining a certificate from the APSC. In 2010, the motions for preliminary injunction were partially granted and upheld on appeal pending a hearing. According to the preliminary injunction, all uncompleted construction work associated with wetlands, streams or rivers at the Turk Plant must immediately stop. Mitigation measures required by the permit are authorized and may be completed. The preliminary injunction affects portions of the water intake and associated piping and portions of the transmission lines. A hearing on SWEPCo's appeal is scheduled for March 2011. In October 2010, the Federal

District Court certified issues relating to the state law claims to the Arkansas Supreme Court, including whether those claims are within the primary jurisdiction of the APSC. The Arkansas Supreme Court accepted the request.

In January 2009, SWEPCo was granted CECPNs by the APSC to build three transmission lines and facilities authorized by the SPP and needed to transmit power from the Turk Plant. Intervenors appealed the CECPN decisions in April 2009 to the Arkansas Court of Appeals. In July 2010, the Hempstead County Hunting Club and other appellants filed with the Arkansas Court of Appeals emergency motions to stay the transmission CECPNs to prohibit SWEPCo from taking ownership of private property and undertaking construction of the transmission lines. The Arkansas Court of Appeals issued a decision in July 2010 remanding all transmission line CECPN appeals to the APSC. As a result, a stay was not ordered and construction continues on the affected transmission lines. In January 2011, the appellants filed requests to withdraw their appeals at the Court of Appeals and the APSC postponed a scheduled hearing pending a ruling on those requests. In February 2011, the Court of Appeals dismissed the appeals, and the APSC subsequently closed the remand docket, finding the CECPN decisions final and non-appealable. As previously discussed, the preliminary injunction issued by the Federal District Court related to the wetlands permit also impacts the uncompleted construction on portions of the transmission lines.

Management expects that SWEPCo will ultimately be able to complete construction of the Turk Plant and related transmission facilities and place those facilities in service. However, if SWEPCo is unable to complete the Turk Plant construction, including the related transmission facilities, and place the Turk Plant in service or if SWEPCo cannot recover all of its investment in and expenses related to the Turk Plant, it would materially reduce future net income and cash flows and materially impact financial condition.

Stall Unit

SWEPCo constructed the Stall Unit, an intermediate load 500 MW natural gas-fired combustion turbine combined cycle generating unit, at its existing Arsenal Hill Plant located in Shreveport, Louisiana. The LPSC and the APSC issued orders capping SWEPCo's Stall Unit construction costs at $ 445 million including AFUDC and excluding related transmission costs. The Stall Unit was placed in service in June 2010. As of December 31, 2010, the Stall Unit cost applicable to the cap was $426 million, including $ 49 million of AFUDC. Management does not expect the final costs of the Stall Unit to exceed the ordered cap. In July 2010, the Stall Unit was placed into Arkansas rates. SWEPCo received CWIP treatment for a portion of the Stall Unit in the 2009 Texas Base Rate Filing. See "2009 Texas Base Rate Filing" section below. The Stall Unit will be phased into Louisiana rates between October 2010 and October 2011.

2009 Texas Base Rate Filing

In August 2009, SWEPCo filed a rate case with the PUCT to increase its base rates by approximately $75 million annually including a return on common equity of 11.5%. The filing included requests for financing cost riders of $ 32 million related to construction of the Stall Unit and Turk Plant, a vegetation management rider of $16 million and other requested increases of $ 27 million. In April 2010, a settlement agreement was approved by the PUCT to increase SWEPCo's base rates by approximately $15 million annually, effective May 2010, including a return on common equity of 10.33%, which consists of $5 million related to construction of the Stall Unit and $ 10 million in other increases. In addition, the settlement agreement decreased annual depreciation expense by $17 million and allowed SWEPCo a $ 10 million one-year surcharge rider to recover additional vegetation management costs that SWEPCo must spend within two years.

Texas Fuel Reconciliation

In May 2010, various intervenors, including the PUCT staff, filed testimony recommending disallowances ranging from $ 3 million to $30 million in SWEPCo's $ 755 million fuel and purchased power costs reconciliation for the period January 2006 through March 2009. In July 2010, Cities Advocating Reasonable Deregulation filed testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP. The testimony included unquantified refund recommendations relating to re-pricing of contract transactions.

In September 2010, the Administrative Law Judges issued a Proposal for Decision (PFD) that recommended a disallowance of a significant portion of the charges under a ten-year gas transportation agreement that began in 2009 for the Mattison Plant located in northwest Arkansas. In January 2011, the PUCT issued an order which overturned a portion of the PFD that recommended a finding of imprudence on the Mattison gas contract. The impact of this order had an immaterial impact on SWEPCo's financial statements.

TCC and TNC Rate Matters

TEXAS RESTRUCTURING

Texas Restructuring Appeals

Pursuant to PUCT restructuring orders, TCC securitized net recoverable stranded generation costs of $ 2.5 billion and is recovering the principal and interest on the securitization bonds through the end of 2020. TCC also refunded other net true-up regulatory liabilities of $375 million during the period October 2006 through June 2008 via a CTC credit rate rider under PUCT restructuring orders. TCC and intervenors appealed the PUCT's true-up related orders. After rulings from the Texas District Court and the Texas Court of Appeals, TCC, the PUCT and intervenors filed petitions for review with the Texas Supreme Court. Review is discretionary and the Texas Supreme Court has not yet determined if it will grant review. The Texas Supreme Court requested a full briefing which has concluded. The following represent issues where either the Texas District Court or the Texas Court of Appeals recommended the PUCT decision be modified:

- The Texas District Court judge determined that the PUCT erred by applying an invalid rule to determine the carrying cost rate for the true-up of stranded costs. The Texas Court of Appeals reversed the District Court's unfavorable decision. An October 2010 decision of the Texas Supreme Court addressing the same issue for another utility upholds the Court of Appeals determination.
- The Texas District Court judge determined that the PUCT improperly reduced TCC's net stranded plant costs for commercial unreasonableness. This favorable decision was affirmed by the Texas Court of Appeals.
- The Texas Court of Appeals determined that the PUCT erred by not reducing stranded costs by the "excess earnings" that had already been refunded to affiliated Retail Electric Providers (REPs). This decision could be unfavorable unless the PUCT allows TCC to recover the refunds previously made to the REPs. See the "TCC Excess Earnings" section below.

Management cannot predict the outcome of the pending court proceedings and the PUCT remand decisions. If TCC ultimately succeeds in its appeals, it could have a favorable effect on future net income, cash flows and possibly financial condition. If intervenors succeed in their appeals, it could reduce future net income and cash flows and possibly impact financial condition.

TCC Deferred Investment Tax Credits and Excess Deferred Federal Income Taxes

In 2006, the PUCT reduced recovery of the amount securitized by $ 103 million of tax benefits and associated carrying costs related to TCC's generation assets. In 2006, TCC obtained a private letter ruling from the IRS which confirmed that such reduction was an IRS normalization violation. In order to avoid a normalization violation, the PUCT agreed to allow TCC to defer refunding the tax benefits of $103 million plus interest through the CTC refund period pending resolution of the normalization issue. In 2008, the IRS issued final regulations, which supported the IRS' private letter ruling which would make the refunding of or the reduction of the amount securitized by such tax benefits a normalization violation. After the IRS issued its final regulations, at the request of the PUCT, the Texas Court of Appeals remanded the tax normalization issue to the PUCT for the consideration of additional evidence including the IRS regulations. TCC is not accruing interest on the $103 million because it is not probable that the PUCT will order TCC to violate the normalization provision of the Internal Revenue Code. If interest were accrued, management estimates interest expense would have been approximately $ 22 million higher for the period July 2008 through December 2010.

Management believes that the PUCT will ultimately allow TCC to retain the deferred amounts, which would have a favorable effect on future net income and cash flows. Although unexpected, if the PUCT fails to issue a favorable order and orders TCC to return the tax benefits to customers, the resulting normalization violation could result in TCC's repayment to the IRS of Accumulated Deferred Investment Tax Credits (ADITC) on all property, including transmission and distribution property. This amount approximates $101 million as of December 31, 2010. It could also lead to a loss of TCC's right to claim accelerated tax depreciation in future tax returns. If TCC is required to repay its ADITC to the IRS and is also required to refund ADITC plus unaccrued interest to customers, it would reduce future net income and cash flows and impact financial condition.

TCC Excess Earnings

In 2005, a Texas appellate court issued a decision finding that a PUCT order requiring TCC to refund to the Retail Electric Providers (REPs) excess earnings prior to and outside of the true-up process was unlawful under the Texas Restructuring Legislation. From 2002 to 2005, TCC refunded $ 55 million of excess earnings, including interest, under the overturned PUCT order. On remand, the PUCT must determine how to implement the Court of Appeals decision given that the unauthorized refunds were made to the REPs in lieu of reducing stranded costs in the true-up proceeding.

Certain parties have taken positions that, if adopted, could result in TCC being required to refund excess earnings and interest through the true-up process without receiving a refund from the REPs. If this were to occur, it would reduce future net income and cash flows and impact financial condition. Management cannot predict the outcome of the excess earnings remand.

OTHER TEXAS RATE MATTERS

Texas Base Rate Appeal

TCC filed a base rate case in 2006 seeking to increase base rates. The PUCT issued an order in 2007 which increased TCC's base rates by $ 20 million, eliminated a merger credit rider of $20 million and reduced depreciation rates by $ 7 million. The PUCT decision was appealed by TCC and various intervenors. On appeal, the Texas District Court affirmed the PUCT in most respects and the Texas Court of Appeals affirmed the Texas District Court's decision. The order became final with an August 2010 Texas Court of Appeals mandate.

ETT 2007 Formation Appeal

ETT is a joint venture between AEP Utilities, Inc. and MidAmerican Energy Holdings Company Texas Transco, LLC. TCC and TNC have sold transmission assets both in service and under construction to ETT. The PUCT approved ETT's initial rates, a request for a transfer of in-service assets and CWIP and a certificate of convenience and necessity (CCN) to operate as a stand alone transmission utility in ERCOT. ETT was allowed a 9.96% return on common equity. Intervenors appealed the PUCT's decision but the Texas Court of Appeals affirmed the PUCT's decision in all material respects. The deadline to appeal this decision to the Texas Supreme Court has expired.

In a separate development, the Texas governor signed a new law that clarifies the PUCT's authority to grant CCNs to transmission only utilities such as ETT. ETT filed an application with the PUCT for a CCN under the new law. In March 2010, the PUCT approved the application for a CCN under the new law.

APCo and WPCo Rate Matters

2009 Virginia Base Rate Case

In July 2009, APCo filed a generation and distribution base rate increase with the Virginia SCC of $154 million annually based on a 13.35% return on common equity. Interim rates, subject to refund, became effective in December 2009 but were discontinued in February 2010 when newly enacted Virginia legislation suspended the collection of interim rates. In July 2010, the Virginia SCC issued an order approving a $ 62 million increase based on a 10.53% return on common equity. The order denied recovery of the Virginia share of the Mountaineer Carbon Capture and Storage Product Validation Facility, which resulted in a pretax write-off of $ 54 million in Other Operation. See "Mountaineer Carbon Capture and Storage Project" section below. In addition, the order allowed the deferral of approximately $25 million of incremental storm expense incurred in 2009. Approximately $ 3 million, including interest, was refunded to customers in September 2010 related to the collection of interim rates.

2010 West Virginia Base Rate Case

In May 2010, APCo and WPCo filed a request with the WVPSC to increase annual base rates by $ 156 million based on an 11.75% return on common equity to be effective March 2011. The filing also included a request for recovery of and a return on the West Virginia jurisdictional share of the Mountaineer Carbon Capture and Storage Product

Validation Facility. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $ 60 million, effective March 2011. The settlement agreement allows APCo to defer and amortize up to $18 million of previously expensed 2009 incremental storm expenses over a period of eight years. A decision from the WVPSC is expected in March 2011.

Mountaineer Carbon Capture and Storage Project

Product Validation Facility (PVF)

APCo and ALSTOM Power, Inc., an unrelated third party, jointly constructed a CO_2 capture validation facility, which was placed into service in September 2009. APCo also constructed and owns the necessary facilities to store the CO_2. In October 2009, APCo started injecting CO_2 into the underground storage facilities. The injection of CO_2 required the recording of an asset retirement obligation and an offsetting regulatory asset. As of December 31, 2010, APCo has recorded a noncurrent regulatory asset of $60 million related to the PVF.

In APCo's July 2009 Virginia base rate filing, APCo requested recovery of and a return on its Virginia jurisdictional share of its project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In July 2010, the Virginia SCC issued a base rate order that denied recovery of the Virginia share of the PVF costs. See "2009 Virginia Base Rate Case" section above.

In APCo's and WPCo's May 2010 West Virginia base rate filing, APCo and WPCo requested recovery of and a return on their West Virginia jurisdictional share of the project costs and recovery of the related asset retirement obligation regulatory asset amortization and accretion. In December 2010, a settlement agreement was filed with the WVPSC to increase annual base rates by $ 60 million, effective March 2011. A decision from the WVPSC is expected in March 2011. If APCo cannot recover its remaining investment in and expenses related to the PVF, it would reduce future net income and cash flows and impact financial condition.

Carbon Capture and Sequestration Project with the Department of Energy (DOE)

During 2010, AEPSC, on behalf of APCo, began the project definition stage for the potential construction of a new commercial scale carbon capture and sequestration (CCS) facility under consideration at the Mountaineer Plant. AEPSC, on behalf of APCo, applied for and was selected to receive funding from the DOE for the project. The DOE will fund 50% of allowable costs incurred for the CCS facility up to a maximum of $334 million. A Front-End Engineering and Design (FEED) study, scheduled for completion during the third quarter of 2011, will refine the total cost estimate for the CCS facility. Results from the FEED study will be evaluated by management before any decision is made to seek the necessary regulatory approvals to build the CCS facility. As of December 31, 2010, APCo has incurred $ 14 million in total costs and has received $5 million of DOE funding resulting in a net $ 9 million balance included in Construction Work In Progress on the Consolidated Balance Sheets. If APCo is unable to recover the costs of the CCS project, it would reduce future net income and cash flows.

APCo's Filings for an IGCC Plant

In 2008, the Virginia SCC issued an order denying APCo's request for a surcharge rate mechanism to provide for the timely recovery of pre-construction costs and the ongoing financing costs of the project during the construction period, as well as the capital costs, operating costs and a return on common equity once the facility is placed into commercial operation. The order was based upon the Virginia SCC's finding that the estimated cost of the plant was uncertain and may escalate. The Virginia SCC also expressed concerns that the estimated costs did not include a retrofitting of carbon capture and sequestration facilities. During 2009, based on the order received in Virginia, the WVPSC removed the IGCC case as an active case from its docket and indicated that the conditional CPCN granted in 2008 must be reconsidered if and when APCo proceeds with the IGCC plant.

Through December 31, 2010, APCo deferred for future recovery pre-construction IGCC costs of approximately $9 million applicable to its West Virginia jurisdiction, approximately $2 million applicable to its FERC jurisdiction and approximately $ 9 million applicable to its Virginia jurisdiction.

APCo will not start construction of the IGCC plant until sufficient assurance of full cost recovery exists in Virginia and West Virginia. If the plant is cancelled, APCo plans to seek recovery of its prudently incurred deferred pre-construction costs which, if not recoverable, would reduce future net income and cash flows and impact financial condition.

APCo's and WPCo's Expanded Net Energy Charge (ENEC) Filing

In September 2009, the WVPSC issued an order approving APCo's and WPCo's March 2009 ENEC request. The approved order provided for recovery of an under-recovered balance plus a projected increase in ENEC costs over a four-year phase-in period with an overall increase of $ 355 million and a first-year increase of $124 million, effective October 2009. The WVPSC also approved a fixed annual carrying cost rate of 4%, effective October 2009, to be applied to the incremental deferred regulatory asset balance that will result from the phase-in plan and lowered annual coal cost projections by $27 million.

In June 2010, the WVPSC approved a settlement agreement for $ 96 million, including $10 million of construction surcharges related to APCo's and WPCo's second year ENEC increase. The settlement agreement provided for recovery of the amounts related to the renegotiated coal contracts and allows APCo to accrue weighted average cost of capital carrying charge on the excess under-recovery balance due to the ENEC phase-in as adjusted for the impacts of Accumulated Deferred Income Taxes. As of December 31, 2010, APCo's ENEC under-recovery balance was $ 361 million, excluding $3 million of unrecognized equity carrying costs, which is included in noncurrent regulatory assets. The new rates became effective in July 2010.

PSO Rate Matters

PSO Fuel and Purchased Power

2006 and Prior Fuel and Purchased Power

The OCC filed a complaint with the FERC related to the allocation of off-system sales margins (OSS) among the AEP operating companies in accordance with a FERC-approved allocation agreement. The FERC issued an adverse ruling in 2008. As a result, PSO recorded a regulatory liability in 2008 to return reallocated OSS to customers. Starting in March 2009, PSO refunded the additional reallocated OSS to its customers through February 2010.

A reallocation of purchased power costs among AEP West companies for periods prior to 2002 resulted in an under-recovery of $ 42 million of PSO fuel costs. PSO recovered the $42 million by offsetting it against an existing fuel over-recovery during the period June 2007 through May 2008. The Oklahoma Industrial Energy Consumers (OIEC) contended that PSO should not have collected the $ 42 million without specific OCC approval. In December 2010, the OCC issued orders which approved PSO's 2006 and prior fuel and purchased power costs without any adjustments.

2008 Fuel and Purchased Power

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 the OIEC recommended the fuel clause adjustment rider be amended so that the shareholder's portion of off-system sales margins decrease from 25% to 10%. The OIEC also recommended that the OCC conduct a comprehensive review of all affiliate transactions during 2007 and 2008. In July 2010, additional testimony regarding the 2007 transfer of ERCOT trading contracts to AEPEP was filed. The testimony included unquantified refund recommendations relating to re-pricing of contract transactions. Hearings are currently scheduled for March 2011. If the OCC were to issue an unfavorable decision, it could reduce future net income and cash flows and impact financial condition.

2008 Oklahoma Base Rate Appeal

In January 2009, the OCC issued a final order approving an $ 81 million increase in PSO's non-fuel base revenues based on a 10.5% return on common equity. The new rates reflecting the final order were implemented with the first billing cycle of February 2009. PSO and intervenors appealed various issues but the Court of Civil Appeals affirmed the OCC's decision. No parties sought rehearing or appeal and, as a result, this case has concluded.

2010 Oklahoma Base Rate Case

In July 2010, PSO filed a request with the OCC to increase annual base rates by $82 million, including $30 million that is currently being recovered through a rider. The requested net annual increase to ratepayers would be $52 million. The requested increase included a $24 million increase in depreciation and an 11.5% return on common equity. In January 2011, the OCC approved a settlement agreement which did not change annual revenue or depreciation rates, but transferred $30 million into base rates that was previously being recovered through a capital investment rider. The order provided a 10.15% return on common equity and new rates were effective in February 2011.

I&M Rate Matters

Indiana Fuel Clause Filing (Cook Plant Unit 1 Fire and Shutdown)

I&M filed applications with the IURC to increase its fuel adjustment charge by approximately $ 53 million for the period of April 2009 through September 2009. The filings sought increases for previously under-recovered fuel clause expenses.

As fully discussed in the "Cook Plant Unit 1 Fire and Shutdown" section of Note 6, Cook Plant Unit 1 (Unit 1) was shut down in September 2008 due to significant turbine damage and a small fire on the electric generator. Unit 1 was placed back into service in December 2009 at slightly reduced power. The unit outage resulted in increased replacement power fuel costs. The filing only requested the cost of replacement power through mid-December 2008, the date when I&M began receiving accidental outage insurance proceeds. I&M committed to absorb the remaining costs of replacement power through the date the unit returned to service, which occurred in December 2009.

I&M reached an agreement with intervenors, which was approved by the IURC in March 2009, to collect its existing prior period under-recovery regulatory asset deferral balance over twelve months instead of over six months as initially proposed. Under the agreement, the fuel factors were placed into effect, subject to refund, and a subdocket was established to consider issues relating to the Unit 1 shutdown including the treatment of the accidental outage insurance proceeds. I&M maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers' bills by $78 million.

In October 2010, the Indiana/Michigan Industrial Group and the Indiana Office of Utility Consumer Counselor filed testimony which recommended I&M pay to customers a portion of the accidental outage insurance proceeds up to the extent not previously paid to customers through the fuel adjustment clause or needed to cover costs not covered by I&M's property damage insurance policy. In January 2011, a settlement agreement was filed with the IURC. The settlement stated (a) that I&M will credit an additional $14 million to customers through the fuel adjustment clause, (b) that the parties to the settlement will not oppose the need to replace the existing low-pressure turbine at Cook Unit 1, and (c) that the parties to the settlement agree that the cost of the replacement should not be offset by the accidental outage insurance proceeds received by I&M. In February 2011, the IURC approved the settlement agreement as filed.

Michigan 2009 Power Supply Cost Recovery (PSCR) Reconciliation (Cook Plant Unit 1 Fire and Shutdown)

In March 2010, I&M filed its 2009 PSCR reconciliation with the MPSC. The filing included an adjustment to exclude from the PSCR the incremental fuel cost of replacement power due to the Unit 1 outage from mid-December 2008 through December 2009, the period during which I&M received and recognized the accidental outage insurance proceeds. Management believes that I&M is entitled to retain the accidental outage insurance proceeds since it made customers whole regarding the replacement power costs. In October 2010, a settlement agreement was filed with the MPSC which included deferring the Unit 1 outage issue to the 2010 PSCR reconciliation, which will be filed in March 2011. If any fuel clause revenues or accidental outage insurance proceeds have to be paid to customers, it would reduce future net income and cash flows and impact financial condition. See the "Cook Plant Unit 1 Fire and Shutdown" section of Note 6.

Michigan Base Rate Filing

In January 2010, I&M filed with the MPSC a request for a $63 million increase in annual base rates based on an 11.75% return on common equity. Starting with the August 2010 billing cycle, I&M, with MPSC authorization, implemented a $ 44 million interim rate increase. The interim increase excluded new trackers and regulatory assets for which I&M was not currently incurring expenses. In October 2010, a settlement agreement was approved by the MPSC to increase annual base rates by $36 million based on a 10.35% return on common equity, effective December 2010, plus separate recovery of approximately $7 million of customer choice implementation costs over a two year period beginning April 2011. In addition, the approved revenue requirement includes the amortization of $6 million in previously expensed restructuring costs over five years, which I&M deferred in October 2010 and began amortizing in December 2010. Also, the approved settlement agreement provided for sharing of off-system sales margins between customers (75%) and I&M (25%) with customers receiving a credit in future Power Supply Cost Recovery proceedings for their jurisdictional share of any off-system sales margins. Through December 2010, I&M recorded a provision for refund of $3 million, including interest, related to interim rates that were in effect through November 2010. In January 2011, I&M filed an application with the MPSC requesting the MPSC find that $3 million, including interest, is the total amount to be refunded to customers. I&M is proposing to refund this amount to customers during April 2011. A decision from the MPSC is pending.

Kentucky Rate Matters

Kentucky Base Rate Filing

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

FERC Rate Matters

Seams Elimination Cost Allocation (SECA) Revenue Subject to Refund

In 2004, AEP eliminated transaction-based through-and-out transmission service (T&O) charges in accordance with FERC orders and collected, at the FERC's direction, load-based charges, referred to as RTO SECA, to partially mitigate the loss of T&O revenues on a temporary basis through March 2006. Intervenors objected to the temporary SECA rates. The FERC set SECA rate issues for hearing and ordered that the SECA rate revenues be collected, subject to refund. The AEP East companies recognized gross SECA revenues of $ 220 million from 2004 through 2006 when the SECA rates terminated.

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

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

In August 2010, the affected companies, including the AEP East companies, filed a compliance filing with the FERC. If the compliance filing is accepted, the AEP East companies would have to pay refunds of approximately $20 million including estimated interest of $ 5 million. The AEP East companies could also potentially receive payments up to approximately $10 million including estimated interest of $ 3 million. A decision is pending from the FERC.

The FERC has approved settlements applicable to $112 million of SECA revenue. The AEP East companies provided reserves for net refunds for SECA settlements applicable to the remaining $108 million of SECA revenues collected. Based on the AEP East companies' analysis of the May 2010 order and the compliance filing, management believes that the reserve is adequate to pay the refunds, including interest, that will be required should the May 2010 order or the compliance filing be made final. Management cannot predict the ultimate outcome of this proceeding at the FERC which could impact future net income and cash flows.

Modification of the Transmission Agreement (TA)

The AEP East companies are parties to the TA that provides for a sharing of the cost of transmission lines operated at 138-kV and above and transmission stations containing extra-high voltage facilities. In June 2009, AEPSC, on behalf of the parties to the TA, filed with the FERC a request to modify the TA. Under the proposed amendments, KGPCo and WPCo will be added as parties to the TA. In addition, the amendments would provide for the allocation of PJM transmission costs generally on the basis of the TA parties' 12-month coincident peak and reimburse transmission revenues based on individual cost of service instead of the MLR method used in the present TA. In October 2010, the FERC approved a settlement agreement for the new TA effective November 1, 2010. The impacts of the settlement agreement will be phased-in for retail rate making purposes in certain jurisdictions over periods of up to four years.

PJM/MISO Market Flow Calculation Settlement Adjustments

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

5. EFFECTS OF REGULATION

Regulatory assets are comprised of the following items:

	December 31, 2010	2009	Remaining Recovery Period
Current Regulatory Assets	(in millions)		
Under-recovered Fuel Costs - earns a return	$ 73	$ 85	1 year
Under-recovered Fuel Costs - does not earn a return	8	-	1 year
Total Current Regulatory Assets	$ 81	$ 85	
Noncurrent Regulatory Assets			
Regulatory assets not yet being recovered pending future proceedings to determine the recovery method and timing:			
Regulatory Assets Currently Earning a Return			
Customer Choice Deferrals - CSPCo, OPCo	$ 59	$ 57	
Storm Related Costs - CSPCo, OPCo, TCC	55	49	
Line Extension Carrying Costs - CSPCo, OPCo	55	43	
Acquisition of Monongahela Power - CSPCo	8	10	
Other Regulatory Assets Not Yet Being Recovered	7	1	
Regulatory Assets Currently Not Earning a Return			
Mountaineer Carbon Capture and Storage Product Validation Facility - APCo	60	111	
Environmental Rate Adjustment Clause - APCo	56	25	
Storm Related Costs - APCo, KGPCo, PSO, SWEPCo	45	-	
Deferred Wind Power Costs - APCo	29	5	
Special Rate Mechanism for Century Aluminum - APCo	13	12	
Acquisition of Monongahela Power - CSPCo	4	-	
Transmission Rate Adjustment Clause - APCo	- (a)	26	
Storm Related Costs - KPCo	- (b)	24	
Other Regulatory Assets Not Yet Being Recovered	4	18	
Total Regulatory Assets Not Yet Being Recovered	395	381	
Regulatory assets being recovered:			
Regulatory Assets Currently Earning a Return			
Fuel Adjustment Clause - OPCo	476	341	2 to 8 years
Expanded Net Energy Charge - APCo	361 (c)	-	3 years
Unamortized Loss on Reacquired Debt	93	99	33 years
Storm Related Costs - PSO	38	53	3 years
RTO Formation/Integration Costs	21	23	9 years
Red Rock Generating Facility - PSO	10	11	46 years
Economic Development Rider - CSPCo, OPCo	1	12	1 year
Other Regulatory Assets Being Recovered	21	23	various
Regulatory Assets Currently Not Earning a Return			
Pension and OPEB Funded Status	2,161	2,139	13 years
Income Taxes, Net	1,097	966	37 years
Cook Nuclear Plant Refueling Outage Levelization - I&M	54	22	3 years
Postemployment Benefits	51	52	4 years
Storm Related Costs - KPCo	21 (b)	-	5 years

Transmission Rate Adjustment Clause - APCo	19 (a)	-	2 years
Asset Retirement Obligation - APCo, I&M	15	16	10 years
Restructuring Transition Costs - TCC	14	25	5 years
Off-system Sales Margin Sharing - I&M	13	18	1 year
Vegetation Management - PSO	13	16	1 year
Virginia Environmental and Reliability Costs Recovery - APCo	4	76	3 years
Expanded Net Energy Charge - APCo	- (c)	282	
Other Regulatory Assets Being Recovered	65	40	various
Total Regulatory Assets Being Recovered	4,548	4,214	
Total Noncurrent Regulatory Assets	$ 4,943	$ 4,595	

(a) Recovery of regulatory asset through the transmission rate adjustment clause.
(b) Recovery of regulatory asset was granted during 2010.
(c) The majority of the balance results from the ENEC phase-in plan and earns a weighted average cost of capital carrying charge.

Regulatory liabilities are comprised of the following items:

	December 31, 2010	December 31, 2009	Remaining Refund Period
Current Regulatory Liability	(in millions)		
Over-recovered Fuel Costs - pays a return	$ 16	$ 65	1 year
Over-recovered Fuel Costs - does not pay a return	1	11	1 year
Total Current Regulatory Liability	$ 17	$ 76	
Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits			
Regulatory liabilities not yet being paid:			
Regulatory Liabilities Currently Paying a Return			
Refundable Construction Financing Costs - SWEPCo	$ 20	$ -	
Other Regulatory Liabilities Not Yet Being Paid	-	3	
Regulatory Liabilities Currently Not Paying a Return			
Over-Recovery of gridSMART® Costs - CSPCo, PSO	10	9	
Other Regulatory Liabilities Not Yet Being Paid	11	10	
Total Regulatory Liabilities Not Yet Being Paid	41	22	
Regulatory liabilities being paid:			
Regulatory Liabilities Currently Paying a Return			
Asset Removal Costs	2,222	2,048	(a)
Advanced Metering Infrastructure Surcharge - TCC, TNC	61	30	10 years
Deferred Investment Tax Credits	32	41	up to 12 years
Excess Earnings - - SWEPCo, TNC	13	11	43 years
Transmission Cost Recovery Rider - CSPCo, OPCo	2	25	1 year
Other Regulatory Liabilities Being Paid	2	2	various
Regulatory Liabilities Currently Not Paying a Return			
Excess Asset Retirement Obligations for Nuclear Decommissioning Liability - I&M	354	281	(b)
Deferred Investment Tax Credits	242	239	up to 76 years
Unrealized Gain on Forward Commitments	60	74	5 years
Spent Nuclear Fuel Liability - I&M	42	41	(b)
Over-recovery of Transition Charges - TCC	38	38	9 years
Deferred State Income Tax Coal Credits - APCo	29	28	9 years
Over-recovery of PJM Expenses - I&M	12	18	1 year
Energy Efficiency/Peak Demand Reduction	10	2	2 years
Other Regulatory Liabilities Being Paid	11	9	various
Total Regulatory Liabilities Being Paid	3,130	2,887	

Total Noncurrent Regulatory Liabilities and Deferred Investment Tax Credits	$ 3,171	$ 2,909

(a) Relieved as removal costs are incurred.
(b) Relieved when plant is decommissioned.

6. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

COMMITMENTS

Construction and Commitments

The AEP System has substantial construction commitments to support its operations and environmental investments. In managing the overall construction program and in the normal course of business, we contractually commit to third-party construction vendors for certain material purchases and other construction services. We forecast approximately $2.5 billion and $2.6 billion of construction expenditures excluding AFUDC and capitalized interest for 2011 and 2012, respectively. The subsidiaries purchase fuel, materials, supplies, services and property, plant and equipment under contract as part of their normal course of business. Certain supply contracts contain penalty provisions for early termination.

The following table summarizes our actual contractual commitments at December 31, 2010:

Contractual Commitments	Less Than 1 year	2-3 years	4-5 years	After 5 years	Total
			(in millions)		
Fuel Purchase Contracts (a)	$ 2,810	$ 3,974	$ 2,543	$ 3,718	$ 13,045
Energy and Capacity Purchase Contracts (b)	69	199	204	1,101	1,573
Total	$ 2,879	$ 4,173	$ 2,747	$ 4,819	$ 14,618

(a) Represents contractual commitments to purchase coal, natural gas, uranium and other consumables as fuel for electric generation along with related transportation of the fuel.
(b) Represents contractual commitments for energy and capacity purchase contracts.

GUARANTEES

We record liabilities for guarantees in accordance with the accounting guidance for "Guarantees." There is no collateral held in relation to any guarantees in excess of our ownership percentages. In the event any guarantee is drawn, there is no recourse to third parties unless specified below.

Letters of Credit

We enter into standby letters of credit with third parties. As Parent, we issue all of these letters of credit in our ordinary course of business on behalf of our subsidiaries. These letters of credit cover items such as gas and electricity risk management contracts, construction contracts, insurance programs, security deposits and debt service reserves.

We have two $1.5 billion credit facilities, of which $750 million may be issued under one credit facility as letters of credit. In June 2010, we terminated one of the $1.5 billion facilities that was scheduled to mature in March 2011 and replaced it with a new $1.5 billion credit facility which matures in 2013 and allows for the issuance of up to $600 million as letters of credit. As of December 31, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $124 million with maturities ranging from January 2011 to November 2011.

In June 2010, we reduced a $627 million credit agreement to $478 million. As of December 31, 2010, $477 million of letters of credit with maturities ranging from March 2011 to April 2011 were issued by subsidiaries under this credit agreement to support variable rate Pollution Control Bonds.

Guarantees of Third-Party Obligations

SWEPCo

As part of the process to receive a renewal of a Texas Railroad Commission permit for lignite mining, SWEPCo provides guarantees of mine reclamation of approximately $65 million. Since SWEPCo uses self-bonding, the guarantee provides for SWEPCo to commit to use its resources to complete the reclamation in the event the work is not completed by Sabine Mining Company (Sabine), a consolidated variable interest entity. This guarantee ends upon depletion of reserves and completion of final reclamation. Based on the latest study, we estimate the reserves will be depleted in 2036 with final reclamation completed by 2046 at an estimated cost of approximately $58 million. As of December 31, 2010, SWEPCo has collected approximately $49 million through a rider for final mine closure and reclamation costs, of which $2 million is recorded in Other Current Liabilities, $25 million is recorded in Deferred Credits and Other Noncurrent Liabilities and $22 million is recorded in Asset Retirement Obligations on our Consolidated Balance Sheets.

Sabine charges SWEPCo, its only customer, all of its costs. SWEPCo passes these costs to customers through its fuel clause.

Indemnifications and Other Guarantees

Contracts

We enter into several types of contracts which require indemnifications. Typically these contracts include, but are not limited to, sale agreements, lease agreements, purchase agreements and financing agreements. Generally, these agreements may include, but are not limited to, indemnifications around certain tax, contractual and environmental matters. With respect to sale agreements, our exposure generally does not exceed the sale price. The status of certain sale agreements is discussed in the "Dispositions" section of Note 7. These sale agreements include indemnifications with a maximum exposure related to the collective purchase price. This maximum exposure of approximately $ 1 billion relates to the Bank of America (BOA) litigation indemnity pertaining to the sale of Houston Pipeline Company in 2005 (see "Enron Bankruptcy" section of this note), of which $448 million is recorded in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the Consolidated Balance Sheet as of December 31, 2010. In February 2011, all matters related to the BOA litigation were resolved and we paid BOA $425 million. There are no material amounts recorded for any indemnifications other than the deferred gain (plus interest and attorneys' fees) related to the BOA litigation which settled in February 2011.

Lease Obligations

We lease certain equipment under master lease agreements. See "Master Lease Agreements" and "Railcar Lease" sections of Note 13 for disclosure of lease residual value guarantees.

ENVIRONMENTAL CONTINGENCIES

Federal EPA Complaint and Notice of Violation

The Federal EPA, certain special interest groups and a number of states alleged that APCo, CSPCo, I&M and OPCo modified certain units at their coal-fired generating plants in violation of the NSR requirements of the CAA. Cases with similar allegations against CSPCo, Dayton Power and Light Company and Duke Energy Ohio, Inc. were also filed related to their jointly-owned units. The cases were settled with the exception of a case involving a jointly-owned Beckjord unit which had a liability trial. Following two liability trials, the jury found no liability at the jointly-owned Beckjord unit. The defendants and the plaintiffs appealed to the Seventh Circuit Court of Appeals. In October 2010, the Seventh Circuit dismissed all remaining claims in these cases. Beckjord is operated by Duke Energy Ohio, Inc.

SWEPCo Citizen Suit and Notice of Violation

In 2005, two special interest groups, Sierra Club and Public Citizen, filed a complaint alleging violations of the CAA at SWEPCo's Welsh Plant. In 2008, a consent decree resolved all claims in the case and in the pending appeal of an altered permit for the Welsh Plant. The consent decree required SWEPCo to install continuous particulate emission monitors at the Welsh Plant, secure 65 MW of renewable energy capacity, fund $2 million in emission reduction, energy efficiency or environmental mitigation projects and pay a portion of plaintiffs' attorneys' fees and costs.

The Federal EPA issued a Notice of Violation (NOV) based on alleged violations of a percent sulfur in fuel limitation and the heat input values listed in a previous state permit similar to the claims made in the citizen suit. The NOV also alleges that a permit alteration issued by the Texas Commission on Environmental Quality in 2007 was improper. In March 2008, SWEPCo met with the Federal EPA to discuss the alleged violations. The Federal EPA did not object to the settlement of the citizen suit and has taken no further action. We are unable to predict the timing of any future action by the Federal EPA. We are unable to determine a range of potential losses that are reasonably possible of occurring.

Carbon Dioxide Public Nuisance Claims

In 2004, eight states and the City of New York filed an action in Federal District Court for the Southern District of New York against AEP, AEPSC, Cinergy Corp, Xcel Energy, Southern Company and Tennessee Valley Authority. The Natural Resources Defense Council, on behalf of three special interest groups, filed a similar complaint against the same defendants. The actions allege that CO_2 emissions from the defendants' power plants constitute a public nuisance under federal common law due to impacts of global warming and sought injunctive relief in the form of specific emission reduction commitments from the defendants. The trial court dismissed the lawsuits.

In September 2009, the Second Circuit Court of Appeals issued a ruling on appeal remanding the cases to the Federal District Court for the Southern District of New York. The Second Circuit held that the issues of climate change and global warming do not raise political questions and that Congress' refusal to regulate CO_2 emissions does not mean that plaintiffs must wait for an initial policy determination by Congress or the President's administration to secure the relief sought in their complaints. The court stated that Congress could enact comprehensive legislation to regulate CO_2 emissions or that the Federal EPA could regulate CO_2 emissions under existing CAA authorities and that either of these actions could override any decision made by the district court under federal common law. The Second Circuit did not rule on whether the plaintiffs could proceed with their state common law nuisance claims. In December 2010, the defendants' petition for review by the U.S. Supreme Court was granted. Briefing is underway and the case will be heard in April 2011. We believe the actions are without merit and intend to continue to defend against the claims.

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

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

Alaskan Villages' Claims

In 2008, the Native Village of Kivalina and the City of Kivalina, Alaska filed a lawsuit in Federal Court in the Northern District of California against AEP, AEPSC and 22 other unrelated defendants including oil and gas companies, a coal company and other electric generating companies. The complaint alleges that the defendants' emissions of

CO_2 contribute to global warming and constitute a public and private nuisance and that the defendants are acting together. The complaint further alleges that some of the defendants, including AEP, conspired to create a false scientific debate about global warming in order to deceive the public and perpetuate the alleged nuisance. The plaintiffs also allege that the effects of global warming will require the relocation of the village at an alleged cost of $95 million to $400 million. In October 2009, the judge dismissed plaintiffs' federal common law claim for nuisance, finding the claim barred by the political question doctrine and by plaintiffs' lack of standing to bring the claim. The judge also dismissed plaintiffs' state law claims without prejudice to refiling in state court. The plaintiffs appealed the decision. Briefing is complete and no date has been set for oral argument. The defendants requested that the court defer setting this case for oral argument until after the Supreme Court issues its decision in the CO_2 public nuisance case discussed above. We believe the action is without merit and intend to defend against the claims. We are unable to determine a range of potential losses that are reasonably possible of occurring.

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

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

Superfund addresses clean-up of hazardous substances that have been released to the environment. The Federal EPA administers the clean-up programs. Several states have enacted similar laws. At December 31, 2010, our subsidiaries are named by the Federal EPA as a Potentially Responsible Party (PRP) for four sites for which alleged liability is unresolved. There are eight additional sites for which our subsidiaries have received information requests which could lead to PRP designation. Our subsidiaries have also been named potentially liable at four sites under state law including the I&M site discussed in the next paragraph. In those instances where we have been named a PRP or defendant, our disposal or recycling activities were in accordance with the then-applicable laws and regulations. Superfund does not recognize compliance as a defense, but imposes strict liability on parties who fall within its broad statutory categories. Liability has been resolved for a number of sites with no significant effect on net income.

In 2008, I&M received a letter from the Michigan Department of Environmental Quality (MDEQ) concerning conditions at a site under state law and requesting I&M take voluntary action necessary to prevent and/or mitigate public harm. I&M started remediation work in accordance with a plan approved by MDEQ and recorded a provision of approximately $11 million. As the remediation work is completed, I&M's cost may continue to increase as new information becomes available concerning either the level of contamination at the site or changes in the scope of remediation required by the MDEQ. We cannot predict the amount of additional cost, if any.

We evaluate the potential liability for each Superfund site separately, but several general statements can be made about our potential future liability. Allegations that materials were disposed at a particular site are often unsubstantiated and the quantity of materials deposited at a site can be small and often nonhazardous. Although Superfund liability has been interpreted by the courts as joint and several, typically many parties are named as PRPs for each site and several of the parties are financially sound enterprises. At present, our estimates do not anticipate material cleanup costs for any of our identified Superfund sites, except the I&M site discussed above.

Amos Plant – State and Federal Enforcement Proceedings

In March 2010, we received a letter from the West Virginia Department of Environmental Protection, Division of Air Quality (DAQ), alleging that at various times in 2007 through 2009 the units at Amos Plant reported periods of excess opacity (indicator of compliance with particulate matter emission limits) that lasted for more than thirty consecutive minutes in a 24-hour period and that certain required notifications were not made. We met with representatives of DAQ to discuss these occurrences and the steps we have taken to prevent a recurrence. DAQ indicated that additional enforcement action may be taken, including imposition of a civil penalty of approximately $240 thousand. We have denied that violations of the reporting requirements occurred and maintain that the proper reporting was done. We continue to discuss the resolution of these issues with DAQ, but cannot predict the outcome of these discussions or the amount of any penalty that may be assessed.

In March 2010, we received a request to show cause from the Federal EPA alleging that certain reporting requirements under Superfund and the Emergency Planning and Community Right-to-Know Act had been violated and inviting us to engage in settlement negotiations. The request includes a proposed civil penalty of approximately $300 thousand. We indicated our willingness to engage in good faith negotiations and provided additional information to representatives of the Federal EPA. We have not admitted that any violations occurred or that the amount of the proposed penalty is reasonable.

Defective Environmental Equipment

As part of our continuing environmental investment program, we chose to retrofit wet flue gas desulfurization systems on several units utilizing the jet bubbling reactor (JBR) technology. The retrofits on two Cardinal Plant units and a Conesville Plant unit are operational. Due to unexpected operating results, we completed an extensive review in 2009 of the design and manufacture of the JBR internal components. Our review concluded that there were fundamental design deficiencies and that inferior and/or inappropriate materials were selected for the internal fiberglass components. We initiated discussions with Black & Veatch, the original equipment manufacturer, to develop a repair or replacement corrective action plan. In 2010, we settled with Black & Veatch and resolved the issues involving the internal components and JBR vessel corrosion. These settlements resulted in an immaterial increase in the capitalized costs of the projects for modification of the scope of the contracts.

NUCLEAR CONTINGENCIES

I&M owns and operates the two-unit 2,191 MW Cook Plant under licenses granted by the Nuclear Regulatory Commission (NRC). We have a significant future financial commitment to dispose of SNF and to safely decommission and decontaminate the plant. The licenses to operate the two nuclear units at the Cook Plant expire in 2034 and 2037. The operation of a nuclear facility also involves special risks, potential liabilities and specific regulatory and safety requirements. By agreement, I&M is partially liable, together with all other electric utility companies that own nuclear generating units, for a nuclear power plant incident at any nuclear plant in the U.S. Should a nuclear incident occur at any nuclear power plant in the U.S., the liability could be substantial.

Decommissioning and Low Level Waste Accumulation Disposal

The cost to decommission a nuclear plant is affected by NRC regulations and the SNF disposal program. Decommissioning costs are accrued over the service life of the Cook Plant. The most recent decommissioning cost study was performed in 2009. According to that study, the estimated cost of decommissioning and disposal of low-level radioactive waste ranges from $831 million to $1.5 billion in 2009 nondiscounted dollars. The wide range in estimated costs is caused by variables in assumptions. I&M recovers estimated decommissioning costs for the Cook Plant in its rates. The amount recovered in rates was $14 million in 2010, $16 million in 2009 and $27 million in 2008. Reduced annual decommissioning cost recovery amounts reflect the units' longer estimated life and operating licenses granted by the NRC. Decommissioning costs recovered from customers are deposited in external trusts.

At December 31, 2010 and 2009, the total decommissioning trust fund balance was $1.2 billion and $1.1 billion, respectively. Trust fund earnings increase the fund assets and decrease the amount remaining to be recovered from ratepayers. The decommissioning costs (including interest, unrealized gains and losses and expenses of the trust funds) increase or decrease the recorded liability.

I&M continues to work with regulators and customers to recover the remaining estimated costs of decommissioning the Cook Plant. However, future net income, cash flows and possibly financial condition would be adversely affected if the cost of SNF disposal and decommissioning continues to increase and cannot be recovered.

SNF Disposal

The Federal government is responsible for permanent SNF disposal and assesses fees to nuclear plant owners for SNF disposal. A fee of one mill per KWH for fuel consumed after April 6, 1983 at the Cook Plant is being collected from customers and remitted to the U.S. Treasury. At December 31, 2010 and 2009, fees and related interest of $265 million and $265 million, respectively, for fuel consumed prior to April 7, 1983 have been recorded as Long-term Debt and funds collected from customers along with related earnings totaling $307 million and $306 million, respectively, to pay the fee are recorded as part of Spent Nuclear Fuel and Decommissioning Trusts. I&M has not paid the government the pre-April 1983 fees due to continued delays and uncertainties related to the federal disposal program.

See “Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal” section of Note 11 for disclosure of the fair value of assets within the trusts.

Nuclear Incident Liability

I&M carries insurance coverage for property damage, decommissioning and decontamination at the Cook Plant in the amount of $1.8 billion. I&M purchases $1 billion of excess coverage for property damage, decommissioning and decontamination. Additional insurance provides coverage for a weekly indemnity payment resulting from an insured accidental outage. I&M utilizes an industry mutual insurer for the placement of this insurance coverage. Participation in this mutual insurance requires a contingent financial obligation of up to $41 million for I&M which is assessable if the insurer’s financial resources would be inadequate to pay for losses.

The Price-Anderson Act, extended through December 31, 2025, establishes insurance protection for public liability arising from a nuclear incident at $12.6 billion and covers any incident at a licensed reactor in the U.S. Commercially available insurance, which must be carried for each licensed reactor, provides $375 million of coverage. In the event of a nuclear incident at any nuclear plant in the U.S., the remainder of the liability would be provided by a deferred premium assessment of $117.5 million on each licensed reactor in the U.S. payable in annual installments of $17.5 million. As a result, I&M could be assessed $235 million per nuclear incident payable in annual installments of $35 million. The number of incidents for which payments could be required is not limited.

In the event of an incident of a catastrophic nature, I&M is initially covered for the first $375 million through commercially available insurance. The next level of liability coverage of up to $12.2 billion would be covered by claims made under the Price-Anderson Act. If the liability were in excess of amounts recoverable from insurance and retrospective claim payments made under the Price-Anderson Act, I&M would seek to recover those amounts from customers through rate increases. In the event nuclear losses or liabilities are underinsured or exceed accumulated funds and recovery from customers is not possible, net income, cash flows and financial condition could be adversely affected.

Cook Plant Unit 1 Fire and Shutdown

In September 2008, I&M shut down Cook Plant Unit 1 (Unit 1) due to turbine vibrations, caused by blade failure, which resulted in significant turbine damage and a small fire on the electric generator. This equipment, located in the turbine building, is separate and isolated from the nuclear reactor. The turbine rotors that caused the vibration were installed in 2006 and are within the vendor’s warranty period. The warranty provides for the repair or replacement of the turbine rotors if the damage was caused by a defect in materials or workmanship. Repair of the property damage and replacement of the turbine rotors and other equipment could cost up to approximately $395 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 and it resumed operations in December 2009 at slightly reduced power. The Unit 1 rotors were repaired and reinstalled due to the extensive lead time required to manufacture and install new turbine rotors. As a result, the replacement of the repaired turbine rotors and other equipment is scheduled for the Unit 1 planned outage in the fall of 2011.

I&M maintains property insurance through NEIL with a $1 million deductible. As of December 31, 2010, we recorded $46 million in Prepayments and Other Current Assets on our Consolidated Balance Sheets representing estimated recoverable amounts under the property insurance policy. Through December 31, 2010, I&M received partial payments of $203 million from NEIL for the cost incurred to date to repair the property damage.

I&M also maintains a separate accidental outage policy with NEIL. In 2009, I&M recorded $185 million in revenue under the policy and reduced the cost of replacement power in customers’ bills by $78 million.

NEIL is reviewing claims made under the insurance policies to ensure that claims associated with the outage are covered by the policies. The review by NEIL includes the timing of the unit’s return to service and whether the return should have occurred earlier reducing the amount received under the accidental outage policy. The treatment of the remaining accidental outage policy revenues through fuel clauses is discussed in "I&M Rate Matters" section of Note 4. The treatment of property damage costs, replacement power costs and insurance proceeds will be the subject of future regulatory proceedings in Indiana and Michigan. 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.

OPERATIONAL CONTINGENCIES

Insurance and Potential Losses

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

See “Nuclear Contingencies” section of this footnote for a discussion of nuclear exposures and related insurance.

Some potential losses or liabilities may not be insurable or the amount of insurance carried may not be sufficient to meet potential losses and liabilities, including, but not limited to, liabilities relating to damage to the Cook Plant and costs of replacement power in the event of an incident at the Cook Plant. Future losses or liabilities, if they occur, which are not completely insured, unless recovered from customers, could have a material adverse effect on our net income, cash flows and financial condition.

Fort Wayne Lease

Since 1975, I&M has leased certain energy delivery assets from the City of Fort Wayne, Indiana under a long-term lease that expired on February 28, 2010. I&M negotiated with Fort Wayne to purchase the assets at the end of the lease, but no agreement was reached prior to the end of the lease.

I&M and Fort Wayne reached a settlement agreement. The agreement, signed in October 2010, is subject to approval by the IURC. I&M filed a petition with the IURC seeking approval. If the agreement is approved, I&M will purchase the remaining leased property and settle claims Fort Wayne asserted. The agreement provides that I&M will pay Fort Wayne a total of $39 million, inclusive of interest, over 15 years and Fort Wayne will recognize that I&M is the exclusive electricity supplier in the Fort Wayne area. I&M will seek recovery in rates of the payments made to Fort Wayne. If the agreement is not approved by the IURC, the parties have the right to terminate the agreement and pursue other relief.

Enron Bankruptcy

In 2001, we purchased Houston Pipeline Company (HPL) from Enron. Various HPL-related contingencies and indemnities from Enron remained unsettled at the date of Enron’s bankruptcy. In connection with our acquisition of HPL, we entered into an agreement with BAM Lease Company, which granted HPL the exclusive right to use approximately 55 billion cubic feet (BCF) of cushion gas required for the normal operation of the Bammel gas storage facility. At the time of our acquisition of HPL, BOA and certain other banks (the BOA Syndicate) and Enron entered into an agreement granting HPL the exclusive use of the cushion gas. Also at the time of our acquisition, Enron and the BOA Syndicate released HPL from all prior and future liabilities and obligations in connection with the financing arrangement. After the Enron bankruptcy, the BOA Syndicate informed HPL of a purported default by Enron under the terms of the financing arrangement. This dispute was being litigated in federal courts in Texas and New York.

In 2007, the judge in the New York action issued a decision on all claims, including those that were pending trial in Texas, granting BOA summary judgment and dismissing our claims. In August 2008, the New York court entered a final judgment of $346 million. In May 2009, the judge awarded $20 million of attorneys’ fees to BOA. In October 2010, the Court of Appeals affirmed the New York district court’s decision as to the final judgment of $346 million plus interest and reversed the New York district court decision as to the judgment dismissing our claims against BOA in the Southern District of Texas.

In 2005, we sold our interest in HPL and 30 BCF of working gas for approximately $1 billion. Although the assets were legally transferred, we were unable to determine all costs associated with the transfer until the BOA litigation was resolved. We indemnified the buyer of HPL against any damages up to the purchase price resulting from the BOA litigation, including the right to use the 55 BCF of natural gas through 2031. As a result, we deferred the entire gain related to the sale of HPL (approximately $380 million) pending resolution of the Enron and BOA disputes.

The deferred gain related to the sale of HPL, plus accrued interest and attorneys' fees related to the New York court's judgment was $448 million at December 31, 2010 and is included in Current Liabilities – Deferred Gain and Accrued Litigation Costs on the Consolidated Balance Sheet. $441 million related to this matter was included in Deferred Credits and Other Noncurrent Liabilities on our Consolidated Balance Sheet at December 31, 2009. The effect of this decision had no impact on consolidated net income for 2010.

In February 2011, we reached a settlement with BOA covering claims in both the New York and Texas proceedings and paid BOA $425 million. The settlement covers all claims with BOA and Enron. We received title to the 55 BCF of natural gas in the Bammel storage facility as part of the settlement. We do not expect the effect of the settlement to have a material impact on our 2011 consolidated net income.

Natural Gas Markets Lawsuits

In 2002, the Lieutenant Governor of California filed a lawsuit in Los Angeles County California Superior Court against numerous energy companies, including AEP, alleging violations of California law through alleged fraudulent reporting of false natural gas price and volume information with an intent to affect the market price of natural gas and electricity. AEP was dismissed from the case. A number of similar cases were also filed in California and in state and federal courts in several states making essentially the same allegations under federal or state laws against the same companies. AEP (or a subsidiary) is among the companies named as defendants in some of these cases. These cases are at various pre-trial stages. In 2008, we settled all of the cases pending against us in California. The settlements did not impact 2008 earnings due to provisions made in prior periods. We will continue to defend each remaining case where an AEP company is a defendant. We believe the remaining exposure is immaterial.

7. ACQUISITIONS, DISPOSITIONS AND DISCONTINUED OPERATIONS

ACQUISITIONS

2010

Valley Electric Membership Corporation (Utility Operations segment)

In November 2009, SWEPCo signed a letter of intent to purchase certain transmission and distribution assets of Valley Electric Membership Corporation (VEMCO). In October 2010, SWEPCo finalized the purchase for approximately $102 million and began serving VEMCO's 30,000 customers in Louisiana.

2009

Oxbow Lignite Company and Red River Mining Company (Utility Operations segment)

On December 29, 2009, SWEPCo purchased 50% of the Oxbow Lignite Company, LLC (OLC) membership interest for $13 million. CLECO acquired the remaining 50% membership interest in the OLC for $13 million. The Oxbow Mine is located near Coushatta, Louisiana and will be used as one of the fuel sources for SWEPCo's and CLECO's jointly-owned Dolet Hills Generating Station. SWEPCo will account for OLC as an equity investment. Also, on December 29, 2009, DHLC purchased mining equipment and assets for $16 million from the Red River Mining Company.

2008

Erlbacher companies (AEP River Operations segment)

In June 2008, AEP River Operations purchased certain barging assets from Missouri Barge Line Company, Missouri Dry Dock and Repair Company and Cape Girardeau Fleeting, Inc. (collectively known as Erlbacher companies) for $35 million. These assets were incorporated into AEP River Operations' business which will diversify its customer base.

DISPOSITIONS

<u>2010</u>

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

TCC and TNC sold, at cost, $66 million and $73 million, respectively, of transmission facilities to ETT for the year ended December 31, 2010.

Intercontinental Exchange, Inc. (ICE) (All Other)

In April 2010, we sold our remaining 138,000 shares of ICE and recognized a $16 million gain ($10 million, net of tax). We recorded the gain in Interest and Investment Income on our Consolidated Statements of Income for the year ended December 31, 2010.

<u>2009</u>

Electric Transmission Texas LLC (ETT) (Utility Operations segment)

In 2009, TCC and TNC sold, at cost, $93 million and $2 million, respectively, of transmission facilities to ETT.

<u>2008</u>

None

DISCONTINUED OPERATIONS

Management periodically assesses our overall business model and makes decisions regarding our continued support and funding of our various businesses and operations. When it is determined that we will seek to exit a particular business or activity and we have met the accounting requirements for reclassification, we will reclassify those businesses or activities as discontinued operations. The assets and liabilities of these discontinued operations are classified in Assets Held for Sale and Liabilities Held for Sale until the time that they are sold.

Certain of our operations were discontinued in 2008. Results of operations of these businesses are classified as shown in the following table:

	U.K. Generation (a) (in millions)
2010 Revenue	$ -
2010 Pretax Income	-
2010 Earnings, Net of Tax	-
2009 Revenue	$ -
2009 Pretax Income	-
2009 Earnings, Net of Tax	-
2008 Revenue	$ 2
2008 Pretax Income	2
2008 Earnings, Net of Tax	12

(a) The 2008 amounts relate primarily to favorable income tax reserve adjustments.

8. BENEFIT PLANS

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

We sponsor a qualified pension plan and two unfunded nonqualified pension plans. Substantially all of our employees are covered by the qualified plan or both the qualified and a nonqualified pension plan. We sponsor OPEB plans to provide medical and life insurance benefits for retired employees.

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

Actuarial Assumptions for Benefit Obligations

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

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

(a) Rates are for base pay only. In addition, an amount is added to reflect target incentive compensation for exempt employees and overtime and incentive pay for nonexempt employees.

N/A Not applicable

We use a duration-based method to determine the discount rate for our plans. A hypothetical portfolio of high quality corporate bonds similar to those included in the Moody's Aa bond index is constructed with a duration matching the benefit plan liability. The composite yield on the hypothetical bond portfolio is used as the discount rate for the plan.

For 2010, the rate of compensation increase assumed varies with the age of the employee, ranging from 3.5% per year to 11.5% per year, with an average increase of 4.95%.

Actuarial Assumptions for Net Periodic Benefit Costs

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

	Pension Plans			Other Postretirement Benefit Plans		
	2010	**2009**	**2008**	**2010**	**2009**	**2008**

Discount Rate	5.60 %	6.00 %	6.00 %	5.85 %	6.10 %	6.20 %
Expected Return on Plan Assets	8.00 %	8.00 %	8.00 %	8.00 %	7.75 %	8.00 %
Rate of Compensation Increase	4.60 %	5.90 %	5.90 %	N/A	N/A	N/A

N/A Not Applicable

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

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

Health Care Trend Rates	2010	2009
Initial	8.00 %	6.50 %
Ultimate	5.00 %	5.00 %
Year Ultimate Reached	2016	2012

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

	1% Increase	1% Decrease
	(in millions)	
Effect on Total Service and Interest Cost Components of Net Periodic Postretirement Health Care Benefit Cost	$ 22	$ (18)
Effect on the Health Care Component of the Accumulated Postretirement Benefit Obligation	255	(209)

Significant Concentrations of Risk within Plan Assets

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

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

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

	Pension Plans		Other Postretirement Benefit Plans	
	2010	**2009**	**2010**	**2009**
Change in Benefit Obligation		(in millions)		
Benefit Obligation at January 1	$ 4,701	$ 4,301	$ 1,941	$ 1,843
Service Cost	111	104	47	42
Interest Cost	253	254	113	110
Actuarial Loss	222	290	164	32
Plan Amendment Prior Service Credit	-	-	(36)	-
Benefit Payments	(480)	(248)	(142)	(120)
Participant Contributions	-	-	29	25
Medicare Subsidy	-	-	9	9
Benefit Obligation at December 31	$ 4,807	$ 4,701	$ 2,125	$ 1,941
Change in Fair Value of Plan Assets				
Fair Value of Plan Assets at January 1	$ 3,403	$ 3,161	$ 1,308	$ 1,018
Actual Gain on Plan Assets	420	482	149	235
Company Contributions	515	8	117	150
Participant Contributions	-	-	29	25
Benefit Payments	(480)	(248)	(142)	(120)
Fair Value of Plan Assets at December 31	$ 3,858	$ 3,403	$ 1,461	$ 1,308
Underfunded Status at December 31	$ (949)	$ (1,298)	$ (664)	$ (633)

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

	Pension Plans		Other Postretirement Benefit Plans	
		December 31,		
	2010	**2009**	**2010**	**2009**
		(in millions)		
Other Current Liabilities - Accrued Short-term Benefit Liability	$ (8)	$ (10)	$ (4)	$ (4)
Employee Benefits and Pension Obligations - Accrued Long-term Benefit Liability	(941)	(1,288)	(660)	(629)
Underfunded Status	$ (949)	$ (1,298)	$ (664)	$ (633)

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

	Pension Plans		Other Postretirement Benefit Plans	
	December 31,			
	2010	2009	2010	2009
Components	(in millions)			
Net Actuarial Loss	$ 2,129	$ 2,096	$ 638	$ 546
Prior Service Cost (Credit)	11	12	(20)	3
Transition Obligation	-	-	3	43
Recorded as				
Regulatory Assets	$ 1,764	$ 1,750	$ 388	$ 380
Deferred Income Taxes	132	125	81	74
Net of Tax AOCI	244	233	152	138

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

	Pension Plans		Other Postretirement Benefit Plans	
	Years Ended December 31,			
	2010	2009	2010	2009
Components	(in millions)			
Actuarial Loss (Gain) During the Year	$ 121	$ 130	$ 121	$ (127)
Prior Service Credit	-	-	(36)	-
Amortization of Actuarial Loss	(89)	(59)	(29)	(42)
Amortization of Transition Obligation	-	-	(27)	(27)
Change for the Year	$ 32	$ 71	$ 29	$ (196)

Pension and Other Postretirement Plans' Assets

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 1,350	$ 2	$ -	$ -	$ 1,352	35.1%
International	403	-	-	-	403	10.4%
Real Estate Investment Trusts	112	-	-	-	112	2.9%
Common Collective Trust - International	-	163	-	-	163	4.2%
Subtotal - Equities	1,865	165	-	-	2,030	52.6%
Fixed Income:						
United States Government and Agency Securities	-	634	-	-	634	16.4%
Corporate Debt	-	672	-	-	672	17.4%
Foreign Debt	-	127	-	-	127	3.3%
State and Local Government	-	23	-	-	23	0.6%
Other - Asset Backed	-	51	-	-	51	1.3%
Subtotal - Fixed Income	-	1,507	-	-	1,507	39.0%
Real Estate	-	-	83	-	83	2.2%
Alternative Investments	-	-	130	-	130	3.4%
Securities Lending	-	254	-	-	254	6.6%
Securities Lending Collateral (a)	-	-	-	(276)	(276)	(7.1) %
Cash and Cash Equivalents (b)	-	127	-	2	129	3.3%
Other - Pending Transactions and Accrued Income (c)	-	-	-	1	1	-%
Total	$ 1,865	$ 2,053	$ 213	$ (273)	$ 3,858	100.0%

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

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

	Alternative	Total

	Real Estate	Investments	Level 3
		(in millions)	
Balance as of January 1, 2010	$ 90	$ 106	$ 196
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(7)	4	(3)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	19	19
Transfers into Level 3	-	-	-
Transfers out of Level 3	-	-	-
Balance as of December 31, 2010	$ 83	$ 130	$ 213

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 584	$ -	$ -	$ -	$ 584	40.0%
International	220	-	-	-	220	15.1%
Common Collective Trust - Global	-	115	-	-	115	7.9%
Subtotal - Equities	804	115	-	-	919	63.0%
Fixed Income:						
Common Collective Trust - Debt	-	48	-	-	48	3.3%
United States Government and Agency Securities	-	93	-	-	93	6.4%
Corporate Debt	-	110	-	-	110	7.5%
Foreign Debt	-	25	-	-	25	1.7%
State and Local Government	-	3	-	-	3	0.2%
Other - Asset Backed	-	1	-	-	1	0.1%
Subtotal - Fixed Income	-	280	-	-	280	19.2%
Trust Owned Life Insurance:						
International Equities	-	49	-	-	49	3.3%
United States Bonds	-	163	-	-	163	11.1%
Cash and Cash Equivalents (a)	21	25	-	1	47	3.2%
Other - Pending Transactions and Accrued Income (b)	-	-	-	3	3	0.2%
Total	$ 825	$ 632	$ -	$ 4	$ 1,461	100.0%

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

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

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

Asset Class	Level 1	Level 2	Level 3 (in millions)	Other	Total	Year End Allocation
Equities:						
Domestic	$ 1,219	$ -	$ -	$ -	$ 1,219	35.8%
International	320	-	-	-	320	9.4%
Real Estate Investment Trusts	87	-	-	-	87	2.6%
Common Collective Trust - International	-	161	-	-	161	4.7%
Subtotal - Equities	1,626	161	-	-	1,787	52.5%
Fixed Income:						
United States Government and Agency Securities	-	233	-	-	233	6.9%
Corporate Debt	-	831	-	-	831	24.4%
Foreign Debt	-	171	-	-	171	5.0%
State and Local Government	-	35	-	-	35	1.0%
Other - Asset Backed	-	27	-	-	27	0.8%
Subtotal - Fixed Income	-	1,297	-	-	1,297	38.1%
Real Estate	-	-	90	-	90	2.7%
Alternative Investments	-	-	106	-	106	3.1%
Securities Lending	-	173	-	-	173	5.1%
Securities Lending Collateral (a)	-	-	-	(196)	(196)	(5.8) %
Cash and Cash Equivalents (b)	-	116	-	4	120	3.5%
Other - Pending Transactions and Accrued Income (c)	-	-	-	26	26	0.8%
Total	$ 1,626	$ 1,747	$ 196	$ (166)	$ 3,403	100.0%

(a) Amounts in "Other" column primarily represent an obligation to repay cash collateral received as part of the Securities Lending Program.

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

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

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

	Real Estate	Alternative Investments	Total Level 3

		(in millions)	
Balance as of January 1, 2009	$ 137	$ 106	$ 243
Actual Return on Plan Assets			
Relating to Assets Still Held as of the Reporting Date	(47)	(14)	(61)
Relating to Assets Sold During the Period	-	1	1
Purchases and Sales	-	13	13
Transfers in and/or out of Level 3	-	-	-
Balance as of December 31, 2009	$ 90	$ 106	$ 196

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

Asset Class	Level 1	Level 2	Level 3	Other	Total	Year End Allocation
			(in millions)			
Equities:						
Domestic	$ 343	$ -	$ -	$ -	$ 343	26.2%
International	375	-	-	-	375	28.7%
Common Collective Trust - Global	-	93	-	-	93	7.1%
Subtotal - Equities	718	93	-	-	811	62.0%
Fixed Income:						
Common Collective Trust - Debt	-	38	-	-	38	2.9%
United States Government and Agency Securities	-	42	-	-	42	3.2%
Corporate Debt	-	141	-	-	141	10.8%
Foreign Debt	-	32	-	-	32	2.4%
State and Local Government	-	6	-	-	6	0.5%
Other - Asset Backed	-	2	-	-	2	0.2%
Subtotal - Fixed Income	-	261	-	-	261	20.0%
Trust Owned Life Insurance:						
International Equities	-	75	-	-	75	5.7%
United States Bonds	-	131	-	-	131	10.0%
Cash and Cash Equivalents (a)	7	14	-	1	22	1.7%
Other - Pending Transactions and Accrued Income (b)	-	-	-	8	8	0.6%
Total	$ 725	$ 574	$ -	$ 9	$ 1,308	100.0%

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

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

Determination of Pension Expense

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.

Accumulated Benefit Obligation	December 31, 2010	2009

	(in millions)	
Qualified Pension Plan	$ 4,659	$ 4,539
Nonqualified Pension Plans	80	90
Total	$ 4,739	$ 4,629

For our underfunded pension plans that had an accumulated benefit obligation in excess of plan assets, the projected benefit obligation, accumulated benefit obligation and fair value of plan assets of these plans at December 31, 2010 and 2009 were as follows:

	Underfunded Pension Plans	
	December 31,	
	2010	2009
	(in millions)	
Projected Benefit Obligation	$ 4,807	$ 4,701
Accumulated Benefit Obligation	$ 4,739	$ 4,629
Fair Value of Plan Assets	3,858	3,403
Underfunded Accumulated Benefit Obligation	$ (881)	$ (1,226)

Estimated Future Benefit Payments and Contributions

We expect contributions and payments for the pension plans of $158 million and the OPEB plans of $86 million during 2011. The estimated pension benefit payments for the unfunded plan and contributions to the trust are at least the minimum amount required by ERISA plus payment of unfunded nonqualified benefits. For the qualified pension plan, we may make additional discretionary contributions to maintain the funded status of the plan. The contribution to the OPEB plans is generally based on the amount of the OPEB plans' periodic benefit costs for accounting purposes as provided in agreements with state regulatory authorities, plus the additional discretionary contribution of our Medicare subsidy receipts.

The table below reflects the total benefits expected to be paid from the plan or from our assets, including both our share of the benefit cost and the participants' share of the cost, which is funded by participant contributions to the plan. Medicare subsidy receipts are shown in the year of the corresponding benefit payments, even though actual cash receipts are expected early in the following year. Future benefit payments are dependent on the number of employees retiring, whether the retiring employees elect to receive pension benefits as annuities or as lump sum distributions, future integration of the benefit plans with changes to Medicare and other legislation, future levels of interest rates and variances in actuarial results. The estimated payments for pension benefits and OPEB are as follows:

	Pension Plans	Other Postretirement Benefit Plans	
	Pension Payments	Benefit Payments	Medicare Subsidy Receipts
		(in millions)	
2011	$ 314	$ 143	$ 11
2012	320	148	12
2013	325	153	13
2014	333	160	14
2015	342	166	15
Years 2016 to 2020, in Total	1,811	931	95

Components of Net Periodic Benefit Cost

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

	Pension Plans			Other Postretirement Benefit Plans		
	Years Ended December 31,					
	2010	2009	2008	2010	2009	2008
	(in millions)					
Service Cost	$ 111	$ 104	$ 100	$ 47	$ 42	$ 42
Interest Cost	253	254	249	113	110	113
Expected Return on Plan Assets	(312)	(321)	(336)	(105)	(80)	(111)
Amortization of Transition Obligation	-	-	-	27	27	27
Amortization of Prior Service Cost	-	-	1	-	-	-
Amortization of Net Actuarial Loss	89	59	37	29	42	9
Net Periodic Benefit Cost	141	96	51	111	141	80
Capitalized Portion	(44)	(30)	(16)	(35)	(44)	(25)
Net Periodic Benefit Cost Recognized as Expense	$ 97	$ 66	$ 35	$ 76	$ 97	$ 55

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

Components	Pension Plans	Other Postretirement Benefit Plans
	(in millions)	
Net Actuarial Loss	$ 121	$ 33
Prior Service Cost (Credit)	1	(2)
Transition Obligation	-	2
Total Estimated 2011 Amortization	$ 122	$ 33
Expected to be Recorded as		
Regulatory Asset	$ 99	$ 19
Deferred Income Taxes	8	5
Net of Tax AOCI	15	9
Total	$ 122	$ 33

American Electric Power System Retirement Savings Plan

We sponsor the American Electric Power System Retirement Savings Plan, a defined contribution retirement savings plan for substantially all employees who are not members of the United Mine Workers of America (UMWA). It is a qualified plan offering participants an opportunity to contribute a portion of their pay with features under Section 401(k) of the Internal Revenue Code. We provided matching contributions of 75% of the first 6% of eligible compensation contributed by an employee in 2008. Effective January 1, 2009, we match the first 1% of eligible employee contributions at 100% and the next 5% of contributions at 70%. The cost for company matching contributions totaled $61 million in 2010, $74 million in 2009 and $71 million in 2008.

UMWA Benefits

We provide UMWA pension, health and welfare benefits for certain unionized mining employees, retirees and their survivors who meet eligibility requirements. UMWA trustees make final interpretive determinations with regard to all benefits. The pension benefits are administered by UMWA trustees and contributions are made to their trust funds. The health and welfare benefits are administered by us and benefits are paid from our general assets. Contributions and benefits paid were not material in 2010, 2009 and 2008.

9. BUSINESS SEGMENTS

Our primary business is our electric utility operations. 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. While our Utility Operations segment remains our primary business segment, other segments include our AEP River Operations segment with significant barging activities and our Generation and Marketing segment, which includes our nonregulated generating, marketing and risk management activities primarily in the ERCOT market area and to a lesser extent Ohio in PJM and MISO. Intersegment sales and transfers are generally based on underlying contractual arrangements and agreements.

Our reportable segments and their related business activities are as follows:

Utility Operations

- Generation of electricity for sale to U.S. retail and wholesale customers.
- Electricity transmission and distribution in the U.S.

AEP River Operations

- Commercial barging operations that annually transport approximately 39 million tons of coal and dry bulk commodities primarily on the Ohio, Illinois and lower Mississippi Rivers. Approximately 46% of the barging is for transportation of agricultural products, 25% for coal, 11% for steel and 18% for other commodities.

Generation and Marketing

- Wind farms and marketing and risk management activities primarily in ERCOT and to a lesser extent Ohio in PJM and MISO.

The remainder of our activities is presented as All Other. While not considered a business 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 are financial derivatives which settle and expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

The tables below present our reportable segment information for years ended December 31, 2010, 2009 and 2008 and balance sheet information as of December 31, 2010 and 2009. These amounts include certain estimates and allocations where necessary.

Year Ended December 31, 2010	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 13,687	$ 566	$ 173	$ 1	$ -	$ 14,427
Other Operating Segments	104	22	-	14	(140)	-
Total Revenues	$ 13,791	$ 588	$ 173	$ 15	$ (140)	$ 14,427
Depreciation and Amortization	$ 1,598	$ 24	$ 30	$ 2	$ (13)(b)	$ 1,641
Interest Income	8	-	2	31	(20)	21
Interest Expense	942	14	20	58	(35)(b)	999
Income Tax Expense (Credit)	650	19	(20)	(6)	-	643
Net Income (Loss)	1,201	37	25	(45)	-	1,218
Gross Property Additions	2,475	23	1	1	-	2,500

Year Ended December 31, 2009	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 12,733 (e)	$ 490	$ 281	$ (15)	$ -	$ 13,489
Other Operating Segments	70 (e)	18	5	36	(129)	-
Total Revenues	$ 12,803	$ 508	$ 286	$ 21	$ (129)	$ 13,489
Depreciation and Amortization	$ 1,561	$ 17	$ 29	$ 2	$ (12)(b)	$ 1,597
Interest Income	4	-	-	47	(40)	11
Interest Expense	916	5	21	86	(55)(b)	973
Income Tax Expense (Credit)	553	23	-	(1)	-	575

Income (Loss) Before Discontinued Operations and Extraordinary Loss	$ 1,329	$ 47	$ 41	$ (47)	$ -	$ 1,370
Extraordinary Loss, Net of Tax	(5)	-	-	-	-	(5)
Net Income (Loss)	$ 1,324	$ 47	$ 41	$ (47)	$ -	$ 1,365
Gross Property Additions	$ 2,813	$ 81	$ 1	$ 1	$ -	$ 2,896

Year Ended December 31, 2008	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments	Consolidated
			(in millions)			
Revenues from:						
External Customers	$ 13,326 (e)	$ 616	$ 485	$ 13	$ -	$ 14,440
Other Operating Segments	240 (e)	30	(122)	9	(157)	-
Total Revenues	$ 13,566	$ 646	$ 363	$ 22	$ (157)	$ 14,440
Depreciation and Amortization	$ 1,450	$ 14	$ 28	$ 2	$ (11)(b)	$ 1,483
Interest Income	42	-	1	78	(65)	56
Interest Expense	915	5	22	94	(79)(b)	957
Income Tax Expense	515	26	17	84	-	642
Income Before Discontinued Operations and Extraordinary Loss	$ 1,123	$ 55	$ 65	$ 133	$ -	$ 1,376
Discontinued Operations, Net of Tax	-	-	-	12	-	12
Net Income	$ 1,123	$ 55	$ 65	$ 145	$ -	$ 1,388
Gross Property Additions	$ 3,871	$ 116	$ 2	$ (29)(c)	$ -	$ 3,960

December 31, 2010	Utility Operations	Nonutility Operations: AEP River Operations	Nonutility Operations: Generation and Marketing	All Other (a)	Reconciling Adjustments (b)	Consolidated
			(in millions)			
Total Property, Plant and Equipment	$ 52,822	$ 574	$ 584	$ 11	$ (251)	$ 53,740
Accumulated Depreciation and Amortization	17,795	110	198	9	(46)	18,066
Total Property, Plant and Equipment - Net	$ 35,027	$ 464	$ 386	$ 2	$ (205)	$ 35,674

Total Assets	$ 48,780	$ 621	$ 881	$ 15,942	$ (15,769)(d)	$ 50,455
Investments in Equity Method Investees	157	3	-	-	-	160

		Nonutility Operations				
	Utility Operations	**AEP River Operations**	**Generation and Marketing**	**All Other (a)**	**Reconciling Adjustments (b)**	**Consolidated**
			(in millions)			
December 31, 2009						
Total Property, Plant and Equipment	$ 50,905	$ 436	$ 571	$ 10	$ (238)	$ 51,684
Accumulated Depreciation and Amortization	17,110	88	168	8	(34)	17,340
Total Property, Plant and Equipment - Net	$ 33,795	$ 348	$ 403	$ 2	$ (204)	$ 34,344
Total Assets	$ 46,930	$ 495	$ 779	$ 15,094	$ (14,950)(d)	$ 48,348
Investments in Equity Method Investees	84	4	-	-	-	88

(a) All Other includes:

- Parent's guarantee revenue received from affiliates, investment income, interest income and interest expense, and other nonallocated costs.
- Tax and interest expense adjustments related to our UK operations which were sold in 2004 and 2002.
- Forward natural gas contracts that were not sold with our natural gas pipeline and storage operations in 2004 and 2005. These contracts are financial derivatives which settle and expire in 2011.
- The 2008 cash settlement of a purchase power and sale agreement with TEM related to the Plaquemine Cogeneration Facility which was sold in 2006. The cash settlement of $255 million ($164 million, net of tax) is included in Net Income.
- Revenue sharing related to the Plaquemine Cogeneration Facility.

(b) Includes eliminations due to an intercompany capital lease.

(c) Gross Property Additions for All Other includes construction expenditures of $8 million in 2008 related to the acquisition of turbines by one of our nonregulated, wholly-owned subsidiaries. These turbines were refurbished and transferred to a generating facility within our Utility Operations segment in the fourth quarter of 2008. The transfer of these turbines resulted in the elimination of $37 million from All Other and the addition of $37 million to Utility Operations.

(d) Reconciling Adjustments for Total Assets primarily include the elimination of intercompany advances to affiliates and intercompany accounts receivable along with the elimination of AEP's investments in subsidiary companies.

(e) PSO and SWEPCo transferred certain existing ERCOT energy marketing contracts to AEP Energy Partners, Inc. (AEPEP) (Generation and Marketing segment) and entered into intercompany financial and physical purchase and sales agreements with AEPEP. As a result, we reported third-party net purchases or sales activity for these energy marketing contracts as Revenues from External Customers for the Utility Operations segment. This was offset by the Utility Operations segment's related net sales (purchases) for these contracts with AEPEP in Revenues from Other Operating Segments of $(5) million and $122 million for the years ended December 31, 2009 and 2008, respectively. The Generation and Marketing segment also reported these purchase or sales contracts with Utility Operations as Revenues from Other Operating Segments. These affiliated contracts between PSO and SWEPCo with AEPEP ended in December 2009.

10. DERIVATIVES AND HEDGING

OBJECTIVES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS

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

STRATEGIES FOR UTILIZATION OF DERIVATIVE INSTRUMENTS TO ACHIEVE OBJECTIVES

Trading Strategies

Our strategy surrounding the use of derivative instruments for trading purposes focuses on seizing market opportunities to create value driven by expected changes in the market prices of the commodities in which we transact.

Risk Management Strategies

Our strategy surrounding the use of derivative instruments focuses on managing our risk exposures, future cash flows and creating value utilizing both economic and formal hedging strategies. To accomplish our objectives, we primarily employ risk management contracts including physical forward purchase and sale contracts, financial forward purchase and sale contracts and financial swap instruments. Not all risk management contracts meet the definition of a derivative under the accounting guidance for "Derivatives and Hedging." Derivative risk management contracts elected normal under the normal purchases and normal sales scope exception are not subject to the requirements of this accounting guidance.

We enter into power, coal, natural gas, interest rate and, to a lesser degree, heating oil and gasoline, emission allowance and other commodity contracts to manage the risk associated with our energy business. We enter into interest rate derivative contracts in order to manage the interest rate exposure associated with our commodity portfolio. For disclosure purposes, such risks are grouped as “Commodity,” as they are related to energy risk management activities. We also engage in risk management of interest rate risk associated with debt financing and foreign currency risk associated with future purchase obligations denominated in foreign currencies. For disclosure purposes, these risks are grouped as “Interest Rate and Foreign Currency.” The amount of risk taken is determined by the Commercial Operations and Finance groups in accordance with our established risk management policies as approved by the Finance Committee of our Board of Directors.

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

Notional Volume of Derivative Instruments

	Volume December 31, 2010	Volume December 31, 2009	Unit of Measure
	(in millions)		
Commodity:			
Power	652	589	MWHs
Coal	63	60	Tons
Natural Gas	94	127	MMBtus
Heating Oil and Gasoline	6	6	Gallons
Interest Rate	$ 171	$ 216	USD
Interest Rate and Foreign Currency	$ 907	$ 83	USD

Fair Value Hedging Strategies

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

Cash Flow Hedging Strategies

We enter into and designate as cash flow hedges certain derivative transactions for the purchase and sale of power, coal, natural gas and heating oil and gasoline (“Commodity”) in order to manage the variable price risk related to the forecasted purchase and sale of these commodities. We monitor the potential impacts of commodity price changes and, where appropriate, enter into derivative transactions to protect profit margins for a portion of future electricity sales and fuel or energy purchases. We do not hedge all commodity price risk.

Our vehicle fleet and barge operations are exposed to gasoline and diesel fuel price volatility. We enter into financial heating oil and gasoline derivative contracts in order to mitigate price risk of our future fuel purchases. For disclosure purposes, these contracts are included with other hedging activity as “Commodity.” We do not hedge all fuel price risk.

We enter into a variety of interest rate derivative transactions in order to manage interest rate risk exposure. Some interest rate derivative transactions effectively modify our exposure to interest rate risk by converting a portion of our floating-rate debt to a fixed rate. We also enter into interest rate derivative contracts to manage interest rate exposure related to anticipated borrowings of fixed-rate debt. Our anticipated fixed-rate debt offerings have a high probability of occurrence as the proceeds will be used to fund existing debt maturities and projected capital expenditures. We do not hedge all interest rate exposure.

At times, we are exposed to foreign currency exchange rate risks primarily when we purchase certain fixed assets from foreign suppliers. In accordance with our risk management policy, we may enter into foreign currency derivative transactions to protect against the risk of increased cash outflows resulting from a foreign currency’s appreciation against the dollar. We do not hedge all foreign currency exposure.

ACCOUNTING FOR DERIVATIVE INSTRUMENTS AND THE IMPACT ON OUR FINANCIAL STATEMENTS

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

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

According to the accounting guidance for "Derivatives and Hedging," we reflect the fair values of our derivative instruments subject to netting agreements with the same counterparty net of related cash collateral. For certain risk management contracts, we are required to post or receive cash collateral based on third party contractual agreements and risk profiles. For the December 31, 2010 and 2009 balance sheets, we netted \$8 million and \$12 million, respectively, of cash collateral received from third parties against short-term and long-term risk management assets and \$109 million and \$98 million, respectively, of cash collateral paid to third parties against short-term and long-term risk management liabilities.

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

Fair Value of Derivative Instruments
December 31, 2010

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)(c)**	**Other (a) (b)**	**Total**
			(in millions)		
Current Risk Management Assets	$ 1,023	$ 18	$ 30	$ (839)	$ 232
Long-term Risk Management Assets	546	12	2	(150)	410
Total Assets	1,569	30	32	(989)	642
Current Risk Management Liabilities	995	13	2	(881)	129
Long-term Risk Management Liabilities	387	6	3	(255)	141
Total Liabilities	1,382	19	5	(1,136)	270
Total MTM Derivative Contract Net Assets (Liabilities)	$ 187	$ 11	$ 27	$ 147	$ 372

Fair Value of Derivative Instruments
December 31, 2009

	Risk Management Contracts	Hedging Contracts			
Balance Sheet Location	**Commodity (a)**	**Commodity (a)**	**Interest Rate and Foreign Currency (a)**	**Other (a) (b)**	**Total**
			(in millions)		
Current Risk Management Assets	$ 1,078	$ 13	$ -	$ (831)	$ 260
Long-term Risk Management Assets	614	-	-	(271)	343
Total Assets	1,692	13	-	(1,102)	603
Current Risk Management Liabilities	997	17	3	(897)	120
Long-term Risk Management Liabilities	442	-	2	(316)	128
Total Liabilities	1,439	17	5	(1,213)	248
Total MTM Derivative Contract Net Assets					

(Liabilities)	$ 253	$ (4)	$ (5)	$ 111	$ 355

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

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

(c) At December 31, 2010, Risk Management Assets included $7 million and Risk Management Liabilities included $1 million related to fair value hedging strategies while the remainder related to cash flow hedging strategies. At December 31, 2009, we only employed cash flow hedging strategies.

The table below presents our activity of derivative risk management contracts for the years ended December 31, 2010 and 2009:

Amount of Gain (Loss) Recognized on Risk Management Contracts

Location of Gain (Loss)	Years Ended December 31, 2010	Years Ended December 31, 2009
	(in millions)	
Utility Operations Revenue	$ 85	$ 144
Other Revenue	9	19
Regulatory Assets (a)	(9)	(28)
Regulatory Liabilities (a)	38	(7)
Total Gain (Loss) on Risk Management Contracts	$ 123	$ 128

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

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

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

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

Accounting for Fair Value Hedging Strategies

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

We record realized and unrealized gains or losses on interest rate swaps that qualify for fair value hedge accounting treatment and any offsetting changes in the fair value of the debt being hedged in Interest Expense on our Consolidated Statements of Income. During 2010, we recognized gains of $6 million on our hedging instruments, offsetting losses of $6 million on our long-term debt and an immaterial amount of hedge ineffectiveness. During 2009, we did not employ any fair value hedging strategies. During 2008, we employed fair value hedging strategies and recognized an immaterial loss and no hedge ineffectiveness.

Accounting for Cash Flow Hedging Strategies

For cash flow hedges (i.e. hedging the exposure to variability in expected future cash flows attributable to a particular risk), we initially report the effective portion of the gain or loss on the derivative instrument as a component of Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets until the period the hedged item affects Net Income. We recognize any hedge ineffectiveness in Net Income immediately during the period of change, except in regulated jurisdictions where hedge ineffectiveness is recorded as a regulatory asset (for losses) or a regulatory liability (for gains).

Realized gains and losses on derivative contracts for the purchase and sale of power, coal, natural gas, and heating oil and gasoline designated as cash flow hedges are included in Revenues, Fuel and Other Consumables Used for Electric Generation or Purchased Electricity for Resale on our Consolidated Statements of Income, or in Regulatory Assets or Regulatory Liabilities on our Consolidated Balance Sheets, depending on the specific nature of the risk being hedged. During 2010, 2009 and 2008, we designated commodity derivatives as cash flow hedges.

We reclassify gains and losses on financial fuel derivative contracts designated as cash flow hedges from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Other Operation expense, Maintenance expense or Depreciation and Amortization expense, as it relates to capital projects, on our Consolidated Statements of Income. During 2010 and 2009, we designated heating oil and gasoline derivatives as cash flow hedges.

We reclassify gains and losses on interest rate derivative hedges related to our debt financings from Accumulated Other Comprehensive Income (Loss) into Interest Expense in those periods in which hedged interest payments occur. During 2010, 2009 and 2008, we designated interest rate derivatives as cash flow hedges.

The accumulated gains or losses related to our foreign currency hedges are reclassified from Accumulated Other Comprehensive Income (Loss) on our Consolidated Balance Sheets into Depreciation and Amortization expense on our Consolidated Statements of Income over the depreciable lives of the fixed assets designated as the hedged items in qualifying foreign currency hedging relationships. During 2010, 2009 and 2008, we designated foreign currency derivatives as cash flow hedges.

During 2009, we recognized a $6 million gain in Interest Expense related to hedge ineffectiveness on interest rate derivatives designated in cash flow hedge strategies. During 2010, 2009 and 2008, hedge ineffectiveness was immaterial or nonexistent for all of the other hedge strategies disclosed above.

The following tables provide details on designated, effective cash flow hedges included in AOCI on our Consolidated Balance Sheets and the reasons for changes in cash flow hedges for the years ended December 31, 2010 and 2009. All amounts in the following tables are presented net of related income taxes.

Total Accumulated Other Comprehensive Income (Loss) Activity for Cash Flow Hedges
Year Ended December 31, 2010

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)
Changes in Fair Value Recognized in AOCI	9	13	22
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	-	-	-
Other Revenue	(7)	-	(7)
Purchased Electricity for Resale	4	-	4
Interest Expense	-	4	4
Regulatory Assets (a)	3	-	3
Regulatory Liabilities (a)	-	-	-
Balance in AOCI as of December 31, 2010	$ 7	$ 4	$ 11

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Balance in AOCI as of December 31, 2008	$ 7	$ (29)	$ (22)
Changes in Fair Value Recognized in AOCI	(6)	11	5
Amount of (Gain) or Loss Reclassified from AOCI to Income Statement/within Balance Sheet:			
Utility Operations Revenue	(15)	-	(15)
Other Revenue	(15)	-	(15)
Purchased Electricity for Resale	29	-	29
Interest Expense	-	5	5
Regulatory Assets (a)	5	-	5
Regulatory Liabilities (a)	(7)	-	(7)
Balance in AOCI as of December 31, 2009	$ (2)	$ (13)	$ (15)

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

During 2008 we reclassified $7 million of gains from AOCI to net income.

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

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 13	$ 25	$ 38
Hedging Liabilities (a)	(2)	(4)	(6)
AOCI Gain (Loss) Net of Tax	7	4	11
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	3	(2)	1

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

	Commodity	Interest Rate and Foreign Currency	Total
		(in millions)	
Hedging Assets (a)	$ 8	$ -	$ 8
Hedging Liabilities (a)	(12)	(5)	(17)
AOCI Gain (Loss) Net of Tax	(2)	(13)	(15)
Portion Expected to be Reclassified to Net Income During the Next Twelve Months	(2)	(4)	(6)

(a) Hedging Assets and Hedging Liabilities are included in Risk Management Assets and Liabilities on our Consolidated Balance Sheets.

The actual amounts that we reclassify from Accumulated Other Comprehensive Income (Loss) to Net Income can differ from the estimate above due to market price changes. As of December 31, 2010, the maximum length of time that we are hedging (with contracts subject to the accounting guidance for "Derivatives and Hedging") our exposure to variability in future cash flows related to forecasted transactions is 41 months.

Credit Risk

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

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

Collateral Triggering Events

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

	December 31, 2010	December 31, 2009
	(in millions)	
Liabilities for Derivative Contracts with Credit Downgrade Triggers	$ 20	$ 10
Amount of Collateral AEP Subsidiaries Would Have Been Required to Post	45	34
Amount Attributable to RTO and ISO Activities	44	29

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

	December 31, 2010	December 31, 2009
	(in millions)	
Liabilities for Contracts with Cross Default Provisions Prior to Contractual Netting Arrangements	$ 401	$ 567
Amount of Cash Collateral Posted	81	15
Additional Settlement Liability if Cross Default Provision is Triggered	213	199

11. FAIR VALUE MEASUREMENTS

Fair Value Measurements of Long-term Debt

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

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

December 31, 2010	December 31, 2009

	Book Value	Fair Value	Book Value	Fair Value
		(in millions)		
Long-term Debt	$ 16,811	$ 18,285	$ 17,498	$ 18,479

Fair Value Measurements of Other Temporary Investments

Other Temporary Investments include marketable securities that we intend to hold for less than one year, investments by our protected cell of EIS and funds held by trustees primarily for the payment of debt. See "Other Temporary Investments" section of Note 1.

The following is a summary of Other Temporary Investments:

	December 31, 2010			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 225	$ -	$ -	$ 225
Fixed Income Securities:				
Mutual Funds	69	-	-	69
Variable Rate Demand Notes	97	-	-	97
Equity Securities - Mutual Funds	18	7	-	25
Total Other Temporary Investments	$ 409	$ 7	$ -	$ 416

	December 31, 2009			
Other Temporary Investments	**Cost**	**Gross Unrealized Gains**	**Gross Unrealized Losses**	**Estimated Fair Value**
		(in millions)		
Restricted Cash (a)	$ 223	$ -	$ -	$ 223
Fixed Income Securities:				
Mutual Funds	57	-	-	57
Variable Rate Demand Notes	45	-	-	45
Equity Securities:				
Domestic	1	15	-	16
Mutual Funds	18	4	-	22
Total Other Temporary Investments	$ 344	$ 19	$ -	$ 363

(a) Primarily represents amounts held for the payment of debt.

The following table provides the activity for our debt and equity securities within Other Temporary Investments for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31,		
	2010	**2009**	**2008**
		(in millions)	
Proceeds From Investment Sales	$ 455	$ 35	$ 1,185
Purchases of Investments	503	82	1,118
Gross Realized Gains on Investment Sales	16	-	-
Gross Realized Losses on Investment Sales	-	-	-

At December 31, 2010 and 2009, we had no Other Temporary Investments with an unrealized loss position. In June 2009, we recorded $9 million ($6 million, net of tax) of other-than-temporary impairments of Other Temporary Investments for equity investments of our protected cell captive insurance company. At December 31, 2010, the fair value of fixed income securities are primarily debt based mutual funds with short and intermediate maturities and variable rate demand notes. Mutual funds may be sold and do not contain maturity dates.

Fair Value Measurements of Trust Assets for Decommissioning and SNF Disposal

I&M records securities held in trust funds for decommissioning nuclear facilities and for the disposal of SNF at fair value. See "Nuclear Trust Funds" section of Note 1.

The following is a summary of nuclear trust fund investments at December 31, 2010 and December 31, 2009:

	December 31, 2010			December 31, 2009		
	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments	Estimated Fair Value	Gross Unrealized Gains	Other-Than-Temporary Impairments
	(in millions)					
Cash and Cash Equivalents	$ 20	$ -	$ -	$ 14	$ -	$ -
Fixed Income Securities:						
United States Government	461	23	(1)	401	13	(4)
Corporate Debt	59	4	(2)	57	5	(2)
State and Local Government	341	(1)	-	369	8	1
Subtotal Fixed Income Securities	861	26	(3)	827	26	(5)
Equity Securities - Domestic	634	183	(123)	551	234	(119)
Spent Nuclear Fuel and Decommissioning Trusts	$ 1,515	$ 209	$ (126)	$ 1,392	$ 260	$ (124)

The following table provides the securities activity within the decommissioning and SNF trusts for the years ended December 31, 2010, 2009 and 2008:

	Years Ended December 31, 2010	2009	2008
	(in millions)		
Proceeds From Investment Sales	$ 1,362	$ 713	$ 732
Purchases of Investments	1,415	771	804
Gross Realized Gains on Investment Sales	12	28	33
Gross Realized Losses on Investment Sales	2	1	7

The adjusted cost of debt securities was $835 million and $801 million as of December 31, 2010 and 2009, respectively.

The fair value of debt securities held in the nuclear trust funds, summarized by contractual maturities, at December 31, 2010 was as follows:

	Fair Value of Debt Securities
	(in millions)
Within 1 year	$ 22
1 year – 5 years	306
5 years – 10 years	257
After 10 years	276
Total	$ 861

Fair Value Measurements of Financial Assets and Liabilities

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

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

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 170	$ -	$ -	$ 124	$ 294
Other Temporary Investments					
Restricted Cash (a)	184	-	-	41	225
Fixed Income Securities:					
Mutual Funds	69	-	-	-	69
Variable Rate Demand Notes	-	97	-	-	97
Equity Securities - Mutual Funds (b)	25	-	-	-	25
Total Other Temporary Investments	278	97	-	41	416
Risk Management Assets					
Risk Management Commodity Contracts (c) (f)	20	1,432	112	(1,013)	551
Cash Flow Hedges:					
Commodity Hedges (c)	11	17	-	(15)	13
Fair Value Hedges	-	7	-	-	7
Interest Rate/Foreign Currency Hedges	-	25	-	-	25
Dedesignated Risk Management Contracts (d)	-	-	-	46	46
Total Risk Management Assets	31	1,481	112	(982)	642
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	8	-	12	20
Fixed Income Securities:					
United States Government	-	461	-	-	461
Corporate Debt	-	59	-	-	59
State and Local Government	-	341	-	-	341
Subtotal Fixed Income Securities	-	861	-	-	861
Equity Securities - Domestic (b)	634	-	-	-	634
Total Spent Nuclear Fuel and Decommissioning Trusts	634	869	-	12	1,515
Total Assets	$ 1,113	$ 2,447	$ 112	$ (805)	$ 2,867
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (f)	$ 25	$ 1,325	$ 27	$ (1,114)	$ 263
Cash Flow Hedges:					
Commodity Hedges (c)	4	13	-	(15)	2

Fair Value Hedges	-	1	-	-	1
Interest Rate/Foreign Currency Hedges	-	4	-	-	4
Total Risk Management Liabilities	$ 29	$ 1,343	$ 27	$ (1,129)	$ 270

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

	Level 1	Level 2	Level 3	Other	Total
Assets:			(in millions)		
Cash and Cash Equivalents (a)	$ 427	$ -	$ -	$ 63	$ 490
Other Temporary Investments					
Restricted Cash (a)	198	-	-	25	223
Fixed Income Securities:					
Mutual Funds	57	-	-	-	57
Variable Rate Demand Notes	-	45	-	-	45
Equity Securities (b):					
Domestic	16	-	-	-	16
Mutual Funds	22	-	-	-	22
Total Other Temporary Investments	293	45	-	25	363
Risk Management Assets					
Risk Management Commodity Contracts (c) (g)	8	1,609	72	(1,119)	570
Cash Flow Hedges:					
Commodity Hedges (c)	1	11	-	(4)	8
Dedesignated Risk Management Contracts (d)	-	-	-	25	25
Total Risk Management Assets	9	1,620	72	(1,098)	603
Spent Nuclear Fuel and Decommissioning Trusts					
Cash and Cash Equivalents (e)	-	3	-	11	14
Fixed Income Securities:					
United States Government	-	401	-	-	401
Corporate Debt	-	57	-	-	57
State and Local Government	-	369	-	-	369
Subtotal Fixed Income Securities	-	827	-	-	827
Equity Securities - Domestic (b)	551	-	-	-	551
Total Spent Nuclear Fuel and Decommissioning Trusts	551	830	-	11	1,392
Total Assets	$ 1,280	$ 2,495	$ 72	$ (999)	$ 2,848
Liabilities:					
Risk Management Liabilities					
Risk Management Commodity Contracts (c) (g)	$ 11	$ 1,415	$ 10	$ (1,205)	$ 231
Cash Flow Hedges:					
Commodity Hedges (c)	-	16	-	(4)	12
Interest Rate/Foreign Currency Hedges	-	5	-	-	5
Total Risk Management Liabilities	$ 11	$ 1,436	$ 10	$ (1,209)	$ 248

(a) Amounts in "Other" column primarily represent cash deposits in bank accounts with financial institutions or with third parties. Level 1 amounts primarily represent investments in money market funds.

(b) Amounts represent publicly traded equity securities and equity-based mutual funds.

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

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

(e) Amounts in "Other" column primarily represent accrued interest receivables from financial institutions. Level 2 amounts primarily represent investments in money market funds.

(f) The December 31, 2010 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($2) million in 2011, $2 million in periods 2012-2014 and ($5) million in periods 2015-2018; Level 2 matures $13 million in 2011, $66 million in periods 2012-2014, $12 million in periods 2015-2016 and $16 million in periods 2017-2028; Level 3 matures $18 million in 2011, $24 million in periods 2012-2014, $16 million in periods 2015-2016 and $27 million in periods 2017-2028. Risk management commodity contracts are substantially comprised of power contracts.

(g) The December 31, 2009 maturity of the net fair value of risk management contracts prior to cash collateral, assets/(liabilities), is as follows: Level 1 matures ($1) million in 2010, ($1) million in periods 2011-2013 and ($1) million in periods 2014-2015; Level 2 matures $65 million in 2010, $84 million in periods 2011-2013, $22 million in periods 2014-2015 and $23 million in periods 2016-2028; Level 3 matures $17 million in 2010, $16 million in periods 2011-2013, $8 million in periods 2014-2015 and $21 million in periods 2016-2028.

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

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

Year Ended December 31, 2010	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2009	$ 62
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	5
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	63
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(25)
Transfers into Level 3 (d) (h)	18
Transfers out of Level 3 (e) (h)	(53)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2010	$ 85

Year Ended December 31, 2009	Net Risk Management Assets (Liabilities)
	(in millions)
Balance as of December 31, 2008	$ 49
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	(4)
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)	
Relating to Assets Still Held at the Reporting Date (a)	44
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-
Purchases, Issuances and Settlements (c)	(17)
Transfers in and/or out of Level 3 (f)	(25)
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	15
Balance as of December 31, 2009	$ 62

Year Ended December 31, 2008	Net Risk Management Assets (Liabilities)	Other Temporary Investments	Investments in Debt Securities
		(in millions)	
Balance as of December 31, 2007	$ 49	$ -	$ -
Realized Gain (Loss) Included in Net Income (or Changes in Net Assets) (a) (b)	-	-	-
Unrealized Gain (Loss) Included in Net Income (or Changes in Net Assets)			
Relating to Assets Still Held at the Reporting Date (a)	12	-	-
Realized and Unrealized Gains (Losses) Included in Other Comprehensive Income	-	-	-
Purchases, Issuances and Settlements (c)	-	(118)	(17)
Transfers in and/or out of Level 3 (f)	(36)	118	17
Changes in Fair Value Allocated to Regulated Jurisdictions (g)	24	-	-
Balance as of December 31, 2008	$ 49	$ -	$ -

(a) Included in revenues on our Consolidated Statements of Income.

(b) Represents the change in fair value between the beginning of the reporting period and the settlement of the risk management commodity contract.

(c) Represents the settlement of risk management commodity contracts for the reporting period.

(d) Represents existing assets or liabilities that were previously categorized as Level 2.

(e) Represents existing assets or liabilities that were previously categorized as Level 3.

(f) Represents existing assets or liabilities that were either previously categorized as a higher level for which the inputs to the model became unobservable or assets and liabilities that were previously classified as Level 3 for which the lowest significant input became observable during the period.

(g) Relates to the net gains (losses) of those contracts that are not reflected on our Consolidated Statements of Income. These net gains (losses) are recorded as regulatory liabilities/assets.

(h) Transfers are recognized based on their value at the beginning of the reporting period that the transfer occurred.

12. INCOME TAXES

The details of our consolidated income taxes before discontinued operations and extraordinary loss as reported are as follows:

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Federal:			
Current	$ (134)	$ (575)	$ 164
Deferred	760	1,171	456
Total Federal	626	596	620
State and Local:			
Current	(20)	(76)	(1)
Deferred	38	55	22
Total State and Local	18	(21)	21
International:			
Current	(1)	-	1
Deferred	-	-	-
Total International	(1)	-	1
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 643	$ 575	$ 642

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

	Years Ended December 31, 2010	2009	2008
		(in millions)	
Net Income	$ 1,218	$ 1,365	$ 1,388
Discontinued Operations, Net of Income Tax of $(10) million in 2008	-	-	(12)
Extraordinary Loss, Net of Income Tax of $3 million in 2009	-	5	-
Income Before Discontinued Operations and Extraordinary Loss	1,218	1,370	1,376
Income Tax Expense Before Discontinued Operations and Extraordinary Loss	643	575	642
Pretax Income	$ 1,861	$ 1,945	$ 2,018
Income Taxes on Pretax Income at Statutory Rate (35%)	$ 651	$ 681	$ 706
Increase (Decrease) in Income Taxes resulting from the following items:			
Depreciation	47	31	23
Investment Tax Credits, Net	(16)	(19)	(19)
Energy Production Credits	(20)	(15)	(20)
State and Local Income Taxes	11	(14)	13
Removal Costs	(19)	(19)	(21)
AFUDC	(33)	(36)	(24)
Medicare Subsidy	12	(11)	(12)

Tax Reserve Adjustments	(16)	(6)	2
Other	26	(17)	(6)
Total Income Tax Expense Before Discontinued Operations and Extraordinary Loss	$ 643	$ 575	$ 642
Effective Income Tax Rate	34.6 %	29.6 %	31.8 %

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

	December 31, 2010	December 31, 2009
	(in millions)	
Deferred Tax Assets	$ 2,519	$ 2,493
Deferred Tax Liabilities	(10,009)	(9,065)
Net Deferred Tax Liabilities	$ (7,490)	$ (6,572)
Property-Related Temporary Differences	$ (5,301)	$ (4,714)
Amounts Due from Customers for Future Federal Income Taxes	(250)	(229)
Deferred State Income Taxes	(622)	(523)
Securitized Transition Assets	(651)	(712)
Regulatory Assets	(867)	(862)
Accrued Pensions	218	335
Deferred Income Taxes on Other Comprehensive Loss	207	203
Accrued Nuclear Decommissioning	(395)	(356)
All Other, Net	171	286
Net Deferred Tax Liabilities	$ (7,490)	$ (6,572)

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

At December 31, 2010, we have federal general business credit carryforwards of $64 million. If these credits are not utilized, they will expire in the years 2028 through 2030.

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

We, along with our subsidiaries, file income tax returns in various state, local and foreign jurisdictions. These taxing authorities routinely examine our tax returns and we are currently under examination in several state and local jurisdictions. We believe that we have filed tax returns with positions that may be challenged by these tax authorities. Management believes that adequate provisions for income taxes have been made for potential liabilities resulting from such challenges and the ultimate resolution of these audits will not materially impact net income. With few exceptions, we are no longer subject to state, local or non-U.S. income tax examinations by tax authorities for years before 2000.

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

We recognize interest accruals related to uncertain tax positions in interest income or expense, as applicable, and penalties in Other Operation in accordance with the accounting guidance for “Income Taxes.”

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

	Years Ended December 31, 2010	2009	2008
	(in millions)		
Interest Expense	$ 8	$ 1	$ 10
Interest Income	11	5	21
Reversal of Prior Period Interest Expense	5	5	13

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

	December 31, 2010	2009
	(in millions)	
Accrual for Receipt of Interest	$ 42	$ 30
Accrual for Payment of Interest and Penalties	21	18

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

	2010	2009	2008
		(in millions)	
Balance at January 1,	$ 237	$ 237	$ 222
Increase - Tax Positions Taken During a Prior Period	40	56	41
Decrease - Tax Positions Taken During a Prior Period	(43)	(65)	(45)
Increase - Tax Positions Taken During the Current Year	-	16	27
Decrease - Tax Positions Taken During the Current Year	(6)	-	(5)
Increase - Settlements with Taxing Authorities	-	1	3
Decrease - Settlements with Taxing Authorities	(2)	-	-
Decrease - Lapse of the Applicable Statute of Limitations	(7)	(8)	(6)
Balance at December 31,	$ 219	$ 237	$ 237

The total amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate is $112 million, $137 million and $147 million for 2010, 2009 and 2008, respectively. We believe there will be no significant net increase or decrease in unrecognized tax benefits within 12 months of the reporting date.

Federal Tax Legislation

Under the Energy Tax Incentives Act of 2005, we filed applications with the United States Department of Energy and the IRS in 2008 for the West Virginia IGCC project and in July 2008 the IRS allocated the project $134 million in credits. In September 2008, we entered into a memorandum of understanding with the IRS concerning the requirements of claiming the credits. We had until July 2010 to meet certain minimum requirements under the agreement with the IRS or the credits would be forfeited. In July 2010, we forfeited the allocated tax credits.

The Economic Stimulus Act of 2008 provided enhanced expensing provisions for certain assets placed in service in 2008 and a 50% bonus depreciation provision similar to the one in effect in 2003 through 2004 for assets placed in service in 2008. The enacted provisions did not have a material impact on net income or financial condition, but provided a cash flow benefit of approximately $ 200 million in 2008.

The American Recovery and Reinvestment Tax Act of 2009 provided for several new grant programs and expanded tax credits and an extension of the 50% bonus depreciation provision enacted in the Economic Stimulus Act of 2008. The enacted provisions did not have a material impact on net income or financial condition. However, the bonus depreciation contributed to the 2009 federal net operating tax loss that resulted in a 2010 cash flow benefit of $419 million.

The Patient Protection and Affordable Care Act and the related Health Care and Education Reconciliation Act (Health Care Acts) were enacted in March 2010. The Health Care Acts amend tax rules so that the portion of employer health care costs that are reimbursed by the Medicare Part D prescription drug subsidy will no longer be deductible by the employer for federal income tax purposes effective for years beginning after December 31, 2012. Because of the loss of the future tax deduction, a reduction in the deferred tax asset related to the nondeductible OPEB liabilities accrued to date was recorded in March 2010. This reduction did not materially affect our cash flows or financial condition. For the year ended December 31, 2010, deferred tax assets decreased $ 56 million, partially offset by recording net tax regulatory assets of $35 million in our jurisdictions with regulated operations, resulting in a decrease in net income of $21 million.

The Small Business Jobs Act (the Act) was enacted in September 2010. Included in the Act was a one-year extension of the 50% bonus depreciation provision. The Tax Relief, Unemployment Insurance Reauthorization and the Job Creation Act of 2010 extended the life of research and development, employment and several energy tax credits originally scheduled to expire at the end of 2010. In addition, the Act extended the time for claiming bonus depreciation and increased the deduction to 100% for part of 2010 and 2011. The enacted provisions will not have a material impact on net income or financial condition but had a favorable impact on cash flows of $ 318 million in 2010.

State Tax Legislation

Under Ohio House Bill 66, in 2005, the Ohio companies established a regulatory liability for $57 million pending rate-making treatment in Ohio. For those companies in which state income taxes flow through for rate-making purposes, regulatory assets associated with the deferred state income tax liabilities were reduced by $22 million. In November 2006, the PUCO ordered that the $57 million be amortized to income as an offset to power supply contract losses incurred by CSPCo and OPCo for sales to Ormet. As of December 31, 2008, the $57 million regulatory liability was fully amortized.

The Ohio legislation also imposed a new commercial activity tax at a fully phased-in rate of 0.26% on all Ohio gross receipts. The tax was phased-in over a five-year period that began July 1, 2005 at 23% of the full 0.26% rate. As a result of this tax, expenses of approximately $13 million, $ 11 million and $9 million were recorded in 2010, 2009 and 2008, respectively, in Taxes Other Than Income Taxes.

Michigan Senate Bill 0094 (MBT Act), effective January 1, 2008, provided a comprehensive restructuring of Michigan's principal business tax. The law replaced the Michigan Single Business Tax. The MBT Act is composed of a new tax which is calculated based upon two components: (a) a business income tax (BIT) imposed at a rate of 4.95% and (b) a modified gross receipts tax (GRT) imposed at a rate of 0.80%, which will collectively be referred to as the BIT/GRT tax calculation. The law also includes significant credits for engaging in Michigan-based activity.

In March 2008, legislation was signed providing for, among other things, a reduction in the West Virginia corporate income tax rate from 8.75% to 8.5% beginning in 2009. The corporate income tax rate could also be reduced to 7.75% in 2012 and 7% in 2013 contingent upon the state government achieving certain minimum levels of shortfall reserve funds. We have evaluated the impact of the law change and the application of the law change will not materially impact our net income, cash flows or financial condition.

13. LEASES

Leases of property, plant and equipment are for periods up to 60 years and require payments of related property taxes, maintenance and operating costs. The majority of the leases have purchase or renewal options and will be renewed or replaced by other leases.

Lease rentals for both operating and capital leases are generally charged to Other Operation and Maintenance expense in accordance with rate-making treatment for regulated operations. Capital leases for nonregulated property are accounted for as if the assets were owned and financed. The components of rental costs are as follows:

Lease Rental Costs	Years Ended December 31, 2010	2009	2008
		(in millions)	
Net Lease Expense on Operating Leases	$ 343	$ 354	$ 368
Amortization of Capital Leases	97	83	97
Interest on Capital Leases	26	13	16
Total Lease Rental Costs	$ 466	$ 450	$ 481

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

Property, Plant and Equipment Under Capital Leases	December 31, 2010	2009
	(in millions)	
Generation	$ 97	$ 75
Distribution	-	-
Other Property, Plant and Equipment	482	379
Construction Work in Progress	-	-
Total Property, Plant and Equipment Under Capital Leases	579	454
Accumulated Amortization	108	139
Net Property, Plant and Equipment Under Capital Leases	$ 471	$ 315
Obligations Under Capital Leases		
Noncurrent Liability	$ 398	$ 244
Liability Due Within One Year	76	73
Total Obligations Under Capital Leases	$ 474	$ 317

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

Future Minimum Lease Payments	Capital Leases	Noncancelable Operating Leases
	(in millions)	
2011	$ 100	$ 306
2012	88	286
2013	71	261
2014	59	241
2015	47	226
Later Years	286	1,349

Total Future Minimum Lease Payments	$ 651	$ 2,669
Less Estimated Interest Element	177	
Estimated Present Value of Future Minimum Lease Payments	$ 474	

Master Lease Agreements

We lease certain equipment under master lease agreements. In December 2010, we signed a new master lease agreement with GE Capital Commercial Inc. (GE) for approximately $137 million to replace existing operating and capital leases with GE. We refinanced approximately $60 million of capital leases and approximately $77 million in operating leases. These assets were included in existing master lease agreements that were to be terminated in 2011 since GE exercised the termination provision related to these leases in 2008. Approximately $16 million of currently leased assets were not included in the refinancing, but will be purchased or refinanced in 2011. In addition, approximately $40 million of operating leases that were previously under lease with GE are now recorded as capital leases after the refinancing. These obligations are included in the future minimum lease payments schedule earlier in this note.

For equipment under the GE master lease agreements, the lessor is guaranteed receipt of up to 84% of the unamortized balance of the equipment at the end of the lease term. If the fair value of the leased equipment is below the unamortized balance at the end of the lease term, we are committed to pay the difference between the fair value and the unamortized balance, with the total guarantee not to exceed 84% of the unamortized balance. For equipment under other master lease agreements, the lessor is guaranteed a residual value up to a stated percentage of either the unamortized balance or the equipment cost at the end of the lease term. If the actual fair value of the leased equipment is below the guaranteed residual value at the end of the lease term, we are committed to pay the difference between the actual fair value and the residual value guarantee. At December 31, 2010, the maximum potential loss for these lease agreements was approximately $14 million ($9 million, net of tax) assuming the fair value of the equipment is zero at the end of the lease term. Historically, at the end of the lease term the fair value has been in excess of the unamortized balance.

Rockport Lease

AEGCo and I&M entered into a sale-and-leaseback transaction in 1989 with Wilmington Trust Company (Owner Trustee), an unrelated, unconsolidated trustee for Rockport Plant Unit 2 (the Plant). The Owner Trustee was capitalized with equity from six owner participants with no relationship to AEP or any of its subsidiaries and debt from a syndicate of banks and securities in a private placement to certain institutional investors.

The gain from the sale was deferred and is being amortized over the term of the lease, which expires in 2022. The Owner Trustee owns the Plant and leases it equally to AEGCo and I&M. The lease is accounted for as an operating lease with the payment obligations included in the future minimum lease payments schedule earlier in this note. The lease term is for 33 years with potential renewal options. At the end of the lease term, AEGCo and I&M have the option to renew the lease or the Owner Trustee can sell the Plant. Neither AEGCo, I&M nor AEP has an ownership interest in the Owner Trustee and do not guarantee its debt. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2010 are as follows:

Future Minimum Lease Payments	AEGCo	I&M
	(in millions)	
2011	$ 74	$ 74
2012	74	74
2013	74	74
2014	74	74
2015	74	74
Later Years	517	517
Total Future Minimum Lease Payments	$ 887	$ 887

Railcar Lease

In June 2003, AEP Transportation LLC (AEP Transportation), a subsidiary of AEP, entered into an agreement with BTM Capital Corporation, as lessor, to lease 875 coal-transporting aluminum railcars. The lease is accounted for as an operating lease. In January 2008, AEP Transportation assigned the remaining 848 railcars under the original lease agreement to I&M (390 railcars) and SWEPCo (458 railcars). The assignment is accounted for as operating leases for I&M and SWEPCo. The initial lease term was five years with three consecutive five-year renewal periods for a maximum lease term of twenty years. I&M and SWEPCo intend to renew these leases for the full lease term of twenty years via the renewal options. The future minimum lease obligations are $17 million for I&M and $19 million for SWEPCo for the remaining railcars as of December 31, 2010. These obligations are included in the future minimum lease payments schedule earlier in this note.

Under the lease agreement, the lessor is guaranteed that the sale proceeds under a return-and-sale option will equal at least a lessee obligation amount specified in the lease, which declines from approximately 84% under the current five year lease term to 77% at the end of the 20-year term of the projected fair value of the equipment. I&M and SWEPCo have assumed the guarantee under the return-and-sale option. I&M's maximum potential loss related to the guarantee is approximately $ 12 million ($8 million, net of tax) and SWEPCo's is approximately $13 million ($9 million, net of tax) assuming the fair value of the equipment is zero at the end of the current five-year lease term. However, we believe that the fair value would produce a sufficient sales price to avoid any loss.

Sabine Dragline Lease

During 2009, Sabine, an entity consolidated in accordance with the accounting guidance for "Variable Interest Entities," entered into capital lease arrangements with a nonaffiliated company to finance the purchase of two electric draglines to be used for Sabine's mining operations totaling $ 47 million. The amounts included in the lease represented the aggregate fair value of the existing equipment and a sale and leaseback transaction for additional dragline rebuild costs required to keep the dragline operational. In addition to the 2009 transactions, Sabine has one additional $53 million dragline completed in 2008 that was financed under a capital lease. These capital lease assets are included in Other Property, Plant and Equipment on our December 31, 2010 and 2009 Consolidated Balance Sheets. The short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities on our December 31, 2010 and 2009 Consolidated Balance Sheets. The future payment obligations are included in our future minimum lease payments schedule earlier in this note.

I&M Nuclear Fuel Lease

In December 2007, I&M entered into a sale-and-leaseback transaction with Citicorp Leasing, Inc. (CLI), an unrelated, unconsolidated, wholly-owned subsidiary of Citibank, N.A. to lease nuclear fuel for I&M's Cook Plant. In December 2007, I&M sold a portion of its unamortized nuclear fuel inventory to CLI at cost for $ 85 million. The lease has a variable rate based on one month LIBOR and is accounted for as a capital lease with lease terms up to 60 months. The future payment obligations of $3 million are included in our future minimum lease payments schedule earlier in this note. The net capital lease asset is included in Other Property, Plant and Equipment and the short-term and long-term capital lease obligations are included in Other Current Liabilities and Deferred Credits and Other Noncurrent Liabilities, respectively, on our December 31, 2010 and 2009 Consolidated Balance Sheets. The future minimum lease payments for this sale-and-leaseback transaction as of December 31, 2010 are as follows, based on estimated fuel burn:

Future Minimum Lease Payments	**Amount**
	(in millions)
2011	$ 2
2012	1
Total Future Minimum Lease Payments	$ 3

14. FINANCING ACTIVITIES

AEP Common Stock

In April 2009, we issued 69 million shares of common stock at $24.50 per share for net proceeds of $1.64 billion, which were primarily used to repay cash drawn under our credit facilities in the second quarter of 2009.

Set forth below is a reconciliation of common stock share activity for the years ended December 31, 2010, 2009 and 2008:

Shares of AEP Common Stock	Issued	Held in Treasury
Balance, December 31, 2007	421,926,696	21,499,992
Issued	4,394,552	-
Treasury Stock Contributed to AEP Foundation	-	(1,250,000)
Balance, December 31, 2008	426,321,248	20,249,992
Issued	72,012,017	-
Treasury Stock Acquired	-	28,866
Balance, December 31, 2009	498,333,265	20,278,858
Issued	2,781,616	-
Treasury Stock Acquired	-	28,867
Balance, December 31, 2010	501,114,881	20,307,725

Preferred Stock

Information about the components of preferred stock of our subsidiaries is as follows:

	December 31, 2010			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (c)	Amount
Not Subject to Mandatory Redemption:				(in millions)
4.00% - 5.00%	$102-$110	1,525,903	600,641	$ 60

	December 31, 2009			
	Call Price Per Share (a)	Shares Authorized (b)	Shares Outstanding (c)	Amount
Not Subject to Mandatory Redemption:				(in millions)
4.00% - 5.00%	$102-$110	1,525,903	606,627	$ 61

(a) At the option of the subsidiary, the shares may be redeemed at the call price plus accrued dividends. The involuntary liquidation preference is $100 per share for all outstanding shares. If the subsidiary defaults on preferred stock dividend payments for a period of one year or longer, preferred stock holders are entitled, voting separately as one class, to elect the number of directors necessary to constitute a majority of the full board of directors of the subsidiary.

(b) As of December 31, 2010 and 2009, our subsidiaries had 14,494,227 and 14,488,294 shares of $100 par value preferred stock, respectively, 22,200,000 shares of $25 par value preferred stock and 7,822,535 and 7,822,482 shares of no par value preferred stock, respectively, that were authorized but unissued. Total shares authorized but unissued include shares not subject to mandatory redemption described in the above table.

(c) The number of preferred stock shares redeemed was 5,986 shares and 251 shares in 2010 and 2009, respectively. There were no preferred stock shares redeemed in 2008.

Long-term Debt

Type of Debt and Maturity	Weighted Average Interest Rate at December 31, 2010	Interest Rate Ranges at December 31, 2010	2009	Outstanding at December 31, 2010	2009
				(in millions)	
Senior Unsecured Notes					
2010-2015	4.99%	0.702%-6.375%	0.464%-6.375%	$ 3,318	$ 4,258
2016-2021	6.12%	5.00%-7.95%	5.00%-7.95%	4,020	4,020
2029-2040	6.41%	5.625%-8.13%	5.625%-8.13%	4,331	4,138
Pollution Control Bonds (a)					
2010-2015 (b)	2.95%	0.29%-6.25%	0.22%-7.125%	1,300	800
2017-2025	5.12%	4.45%-6.05%	0.23%-6.05%	443	595
2026-2042	5.19%	4.40%-6.30%	0.20%-6.30%	520	764
Notes Payable (c)					
2011-2026	5.44%	2.07%-8.03%	4.47%-8.03%	396	326
Securitization Bonds					
2010-2020	5.36%	4.98%-6.25%	4.98%-6.25%	1,847	1,995
Junior Subordinated Debentures (d)					
2063	8.75%	8.75%	8.75%	315	315
Spent Nuclear Fuel Obligation (e)				265	265
Other Long-term Debt					
2011-2059	1.72%	1.3125%-13.718%	1.25%-13.718%	91	88
Unamortized Discount (net)				(35)	(66)
Total Long-term Debt Outstanding				16,811	17,498
Less Portion Due Within One Year				1,309	1,741
Long-term Portion				$ 15,502	$ 15,757

(a) For certain series of pollution control bonds, interest rates are subject to periodic adjustment. Certain series may be purchased on demand at periodic interest adjustment dates. Letters of credit from banks, standby bond purchase agreements and insurance policies support certain series.

(b) Certain pollution control bonds are subject to mandatory redemption earlier than the maturity date. Consequently, these bonds have been classified for maturity and repayment purposes based on the mandatory redemption date.

(c) Notes payable represent outstanding promissory notes issued under term loan agreements and revolving credit agreements with a number of banks and other financial institutions. At expiration, all notes then issued and outstanding are due and payable. Interest rates are both fixed and variable. Variable rates generally relate to specified short-term interest rates.

(d) Debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013.

(e) Spent nuclear fuel obligation consists of a liability along with accrued interest for disposal of spent nuclear fuel (see “SNF Disposal” section of Note 6).

At December 31, 2010, $50 million of PSO’s Senior Unsecured Notes, which are due within one year, are classified as long-term debt due to our intent and ability to refinance these notes on a long-term basis. In January 2011, PSO issued $250 million of 4.4% Senior Unsecured Notes due in 2021, demonstrating the ability to refinance these obligations on a long-term basis.

At December 31, 2009, approximately $472 million of variable-rate, tax-exempt bonds were outstanding. These bonds, which are short-term obligations, were classified as long-term due to our intent and ability to refinance each obligation on a long-term basis. At December 31, 2009, our $478 million credit facility had non-cancelable terms in excess of one year, demonstrating the ability to refinance these short-term obligations on a long-term basis.

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

	2011	2012	2013	2014	2015	After 2015	Total
				(in millions)			
Principal Amount	$ 1,309	$ 815	$ 1,344	$ 941	$ 1,490	$ 10,947	$ 16,846
Unamortized Discount							(35)
Total Long-term Debt Outstanding							$ 16,811

In January 2011, TCC retired $92 million of its outstanding Securitization Bonds.

In February 2011, APCo issued $65 million of 2% Pollution Control Bonds due in 2041 with a 2012 mandatory put date.

As of December 31, 2010, trustees held, on our behalf, $303 million of our reacquired variable rate tax-exempt long-term debt.

Dividend Restrictions

Parent Restrictions

The holders of our common stock are entitled to receive the dividends declared by our Board of Directors provided funds are legally available for such dividends. Our income derives from our common stock equity in the earnings of our utility subsidiaries.

Pursuant to the leverage restrictions in our credit agreements, we must maintain a percentage of debt to total capitalization at a level that does not exceed 67.5%. The payment of cash dividends indirectly results in an increase in the percentage of debt to total capitalization of the company distributing the dividend. The method for calculating outstanding debt and capitalization is contractually defined in the credit agreements. None of AEP's retained earnings were restricted for the purpose of the payment of dividends.

We have issued $315 million of Junior Subordinated Debentures. The debentures will mature on March 1, 2063, subject to extensions to no later than March 1, 2068, and are callable at par any time on or after March 1, 2013. We have the option to defer interest payments on the 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 anticipate any deferral of those interest payments in the foreseeable future.

Utility Subsidiaries' Restrictions

Various financing arrangements, charter provisions and regulatory requirements may impose certain restrictions on the ability of our utility subsidiaries to transfer funds to us in the form of dividends. Specifically, most of our public utility subsidiaries have revolving credit agreements that contain a covenant that limits their debt to capitalization ratio to 67.5%. At December 31, 2010, the amount of restricted net assets of AEP's subsidiaries that may not be distributed to Parent in the form of a loan, advance or dividend was approximately $7 billion.

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

Lines of Credit and Short-term Debt

We use our commercial paper program to meet the short-term borrowing needs of our subsidiaries. The program is used to fund both a Utility Money Pool, which funds the utility subsidiaries, and a Nonutility Money Pool, which funds the majority of the nonutility subsidiaries. In addition, the program also funds, as direct borrowers, the short-term debt requirements of other subsidiaries that are not participants in either money pool for regulatory or operational reasons. As of December 31, 2010, we had credit facilities totaling $3 billion to support our commercial paper program (see "Credit Facilities" section below). The maximum amount of commercial paper outstanding during 2010 was $868 million and the weighted average interest rate of commercial paper outstanding during the year was 0.43%. Our outstanding short-term debt was as follows:

	December 31,			
	2010		2009	
Type of Debt	**Outstanding Amount**	**Interest Rate (a)**	**Outstanding Amount**	**Interest Rate (a)**
	(in millions)		**(in millions)**	
Securitized Debt for Receivables (b)	$ 690	0.31 %	$ -	-
Commercial Paper	650	0.52 %	119	0.26 %
Line of Credit – Sabine Mining Company (c)	6	2.15 %	7	2.06 %
Total Short-term Debt	$ 1,346		$ 126	

(a) Weighted average rate.

(b) Amount of securitized debt for receivables as accounted for under the "Transfers and Servicing" accounting guidance. See "ASU 2009-16 'Transfers and Servicing' " section of Note 2.

(c) Sabine Mining Company is a consolidated variable interest entity. This line of credit does not reduce available liquidity under AEP's credit facilities.

Credit Facilities

We have credit facilities totaling $3 billion to support our commercial paper program. The facilities are structured as two $1.5 billion credit facilities, of which $750 million may be issued under the credit facility that matures in April 2012 as letters of credit. In June 2010, we terminated one of the $1.5 billion facilities, which was scheduled to mature in March 2011, and replaced it with a new $1.5 billion credit facility which matures in June 2013 and allows for the issuance of up to $600 million as letters of credit. As of December 31, 2010, the maximum future payments for letters of credit issued under the two $1.5 billion credit facilities were $124 million.

In June 2010, we reduced a $627 million credit agreement that matures in April 2011 to $478 million. Under the facility, we may issue letters of credit. As of December 31, 2010, $477 million of letters of credit were issued by subsidiaries under this credit agreement to support variable rate Pollution Control Bonds.

Securitized Accounts Receivable – AEP Credit

AEP Credit has a receivables securitization agreement with bank conduits. Under the securitization agreement, AEP Credit receives financing from the bank conduits for the interest in the receivables AEP Credit acquires from affiliated utility subsidiaries. Prior to January 1, 2010, this transaction constituted a sale of receivables in accordance with the accounting guidance for "Transfers and Servicing," allowing the receivables to be removed from our Consolidated Balance Sheet. See "ASU 2009-16 'Transfers and Servicing' " section of Note 2 for discussion of the impact of new accounting guidance effective January 1, 2010 whereby such future transactions do not constitute a sale of receivables and will be accounted for as financings. AEP Credit continues to service the receivables. These securitized transactions allow AEP Credit to repay its outstanding debt obligations, continue to purchase our operating companies' receivables and accelerate AEP Credit's cash collections.

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

Accounts receivable information for AEP Credit is as follows:

	Years Ended December 31,		
	2010	2009	2008
	(dollars in millions)		
Proceeds from Sale of Accounts Receivable	$ N/A	$ 7,043	$ 7,717
Loss on Sale of Accounts Receivable	N/A	3	20
Average Variable Discount Rate on Sale of Accounts Receivable	N/A	0.57%	3.19%
Effective Interest Rates on Securitization of Accounts Receivable	0.31%	N/A	N/A
Net Uncollectible Accounts Receivable Written Off	22	28	23

	December 31,	
	2010	2009
	(in millions)	
Accounts Receivable Retained Interest and Pledged as Collateral Less Uncollectible Accounts	$ 923	$ 160
Deferred Revenue from Servicing Accounts Receivable	N/A	1
Retained Interest if 10% Adverse Change in Uncollectible Accounts	N/A	158
Retained Interest if 20% Adverse Change in Uncollectible Accounts	N/A	156
Total Principal Outstanding	690	656
Derecognized Accounts Receivable	N/A	631
Delinquent Securitized Accounts Receivable	50	29
Bad Debt Reserves Related to Securitization/Sale of Accounts Receivable	26	20
Unbilled Receivables Related to Securitization/Sale of Accounts Receivable	354	376

N/A Not Applicable

Customer accounts receivable retained and securitized for our operating companies are managed by AEP Credit. AEP Credit's delinquent customer accounts receivable represents accounts greater than 30 days past due.

15. STOCK-BASED COMPENSATION

As approved by shareholder vote, the Amended and Restated American Electric Power System Long-Term Incentive Plan (LTIP) authorizes the use of 20,000,000 shares of AEP common stock for various types of stock-based compensation awards, including stock options, to employees. A maximum of 10,000,000 shares may be used under this plan for full value share awards, which includes performance units, restricted shares and restricted stock units. The AEP Board of Directors and shareholders last approved the LTIP in 2010. The following sections provide further information regarding each type of stock-based compensation award granted by the Human Resources Committee of the Board of Directors (HR Committee).

Stock Options

We did not grant stock options in 2010, 2009 or 2008 but we do have outstanding stock options from grants in earlier periods that vested or were exercised in these years. The exercise price of all outstanding stock options equaled or exceeded the market price of AEP's common stock on the date of grant. All outstanding stock options were granted with a ten-year term and generally vested, subject to the participant's continued employment, in approximately equal 1/3 increments on January 1st of the year following the first, second and third anniversary of the grant date. We record compensation cost for stock options over the vesting period based on the fair value on the grant date. The LTIP does not specify a maximum contractual term for stock options.

The total fair value of stock options vested and the total intrinsic value of options exercised are as follows:

Stock Options	Years Ended December 31, 2010	2009	2008
		(in thousands)	
Fair Value of Stock Options Vested	$ -	$ 25	$ 25
Intrinsic Value of Options Exercised (a)	2,058	106	655

(a) Intrinsic value is calculated as market price at exercise dates less the option exercise price.

A summary of AEP stock option transactions during the years ended December 31, 2010, 2009 and 2008 is as follows:

	2010		2009		2008	
	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price	Options	Weighted Average Exercise Price
	(in thousands)		(in thousands)		(in thousands)	
Outstanding at January 1,	1,089	$ 32.78	1,128	$ 32.73	1,196	$ 32.69
Granted	-	N/A	-	N/A	-	N/A
Exercised/Converted	(448)	31.53	(21)	27.20	(68)	31.97
Forfeited/Expired	(90)	38.44	(18)	36.28	-	N/A
Outstanding at December 31,	551	32.88	1,089	32.78	1,128	32.73
Options Exercisable at December 31,	551	$ 32.88	1,089	$ 32.78	1,125	$ 32.72

The following table summarizes information about AEP stock options outstanding and exercisable at December 31, 2010:

2010 Range of Exercise Prices	Number of Options Outstanding and Exercisable	Weighted Average Remaining Life	Weighted Average Exercise Price	Aggregate Intrinsic Value
	(in thousands)	(in years)		(in thousands)
$27.06-27.95	266	2.20	$ 27.44	$ 2,273
$30.76-38.65	159	3.10	31.26	778
$44.10-49.00	126	0.50	46.40	-
Total	551	2.08	32.88	$ 3,051

We include the proceeds received from exercised stock options in common stock and paid-in capital.

Performance Units

Our performance units have a value upon vesting equal to the market value of shares of AEP common stock. The number of performance units held is multiplied by the performance score to determine the actual number of performance units realized. The performance score is determined at the end of the performance period based on performance measures, which include both performance and market conditions, established for each grant at the beginning of the performance period by the HR Committee and can range from 0% to 200%. For the three-year performance and vesting period ending in 2009 and earlier performance periods, performance units are paid in cash or stock at the employee's election unless they are needed to satisfy a participant's stock ownership requirement. Starting with the three-year performance and vesting period ending in 2010 and later, performance units are paid in cash, unless they are needed to satisfy a participant's stock ownership requirement. In that case, the number of units needed to satisfy the participant's largest stock ownership requirement is mandatorily deferred as AEP Career Shares until after the end of the participant's AEP career. AEP Career Shares are a form of non-qualified deferred compensation that have a value equivalent to shares of AEP common stock and are paid in cash after the participant's termination of employment. Amounts equivalent to cash dividends on both performance units and

AEP Career Shares accrue as additional units. We recorded compensation cost for performance units over the three-year vesting period. The liability for both the performance units and AEP Career Shares, recorded in Employee Benefits and Pension Obligations on our Consolidated Balance Sheets, is adjusted for changes in value. The fair value of performance unit awards is based on the estimated performance score and the current 20-day average closing price of AEP common stock at the date of valuation.

The HR Committee awarded performance units and reinvested dividends on outstanding performance units and AEP Career Shares for the years ended December 31, 2010, 2009 and 2008 as follows:

Performance Units	Years Ended December 31, 2010	2009	2008
Awarded Units (in thousands)	736	1,179	1,384
Weighted Average Unit Fair Value at Grant Date	$ 35.43	$ 34.32	$ 30.11
Vesting Period (in years)	3	3	3

Performance Units and AEP Career Shares (Reinvested Dividends Portion)	Years Ended December 31, 2010	2009	2008
Awarded Units (in thousands)	211	224	149
Weighted Average Grant Date Fair Value	$ 34.70	$ 28.82	$ 37.21
Vesting Period (in years)	(a)	(a)	(a)

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

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

The certified performance scores and units earned for the three-year period ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31, 2010	2009	2008
Certified Performance Score	55.8 %	73.5 %	120.3 %
Performance Units Earned	489,013	593,175	1,088,302
Performance Units Manditorily Deferred as AEP Career Shares	33,501	26,635	42,214
Performance Units Voluntarily Deferred into the Incentive Compensation			
Deferral Program	6,583	27,855	66,415
Performance Units to be Paid in Cash	448,929	538,685	979,673

The cash payouts for the years ended December 31, 2010, 2009 and 2008 were as follows:

	Years Ended December 31, 2010	2009	2008

		(in thousands)	
Cash Payouts for Performance Units	$ 18,683	$ 30,034	$ 52,960
Cash Payouts for AEP Career Share Distributions	3,594	2,184	1,236

Restricted Shares and Restricted Stock Units

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

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

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

The HR Committee awarded RSUs, including units awarded for dividends, for the years ended December 31, 2010, 2009 and 2008 as follows:

Restricted Stock Units	Years Ended December 31, 2010	2009	2008
Awarded Units (in thousands)	873	130	56
Weighted Average Grant Date Fair Value	$ 35.24	$ 29.29	$ 41.69

The total fair value and total intrinsic value of restricted shares and restricted stock units vested during the years ended December 31, 2010, 2009 and 2008 were as follows:

Restricted Shares and Restricted Stock Units	Years Ended December 31, 2010	2009	2008
	(in thousands)		
Fair Value of Restricted Shares and Restricted Stock Units Vested	$ 6,044	$ 6,573	$ 2,619
Intrinsic Value of Restricted Shares and Restricted Stock Units Vested (a)	5,993	5,445	2,534

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

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

Nonvested Restricted Shares and Restricted Stock Units	Shares/ Units	Weighted Average Grant Date Fair Value

	(in thousands)		
Nonvested at January 1, 2010	366	$	34.12
Granted	873		35.24
Vested	(173)		35.00
Forfeited	(40)		35.01
Nonvested at December 31, 2010	1,026		34.88

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

Other Stock-Based Plans

We also have a Stock Unit Accumulation Plan for Non-employee Directors providing each non-employee director with AEP stock units as a substantial portion of their quarterly compensation for their services as a director. Amounts equivalent to cash dividends on the stock units accrue as additional AEP stock units. The non-employee directors vest immediately upon award of the stock units. Stock units are paid in cash upon termination of board service or up to 10 years later if the participant so elects. Cash payments for stock units are calculated based on the average closing price of AEP common stock for the 20 trading days immediately preceding the payment date.

We recorded the compensation cost for stock units when the units are awarded and adjusted the liability for changes in value based on the current 20-day average closing price of AEP common stock at the date of valuation.

We had no material cash payouts for stock unit distributions for the years ended December 31, 2010, 2009 and 2008.

The Board of Directors awarded stock units, including units awarded for dividends, for the years ended December 31, 2010, 2009 and 2008 as follows:

Stock Unit Accumulation Plan for Non-Employee Directors	Years Ended December 31, 2010	2009	2008
Awarded Units (in thousands)	54	56	43
Weighted Average Grant Date Fair Value	$ 34.67	$ 29.56	$ 37.72

Share-based Compensation Plans

Compensation cost and the actual tax benefit realized for the tax deductions from compensation cost for share-based payment arrangements recognized in income and total compensation cost capitalized in relation to the cost of an asset for the years ended December 31, 2010, 2009 and 2008 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2010	2009	2008
	(in thousands)		
Compensation Cost for Share-based Payment Arrangements (a)	$ 28,116	$ 31,165	$ (18,028)(b)
Actual Tax Benefit Realized	9,841	10,908	(6,310)(b)
Total Compensation Cost Capitalized	4,689	5,956	(5,026)(b)

(a) Compensation cost for share-based payment arrangements is included in Other Operation and Maintenance expenses on our Consolidated Statements of Income.

(b) In 2008, AEP's declining total shareholder return and lower stock price significantly reduced the accruals for performance units.

During the years ended December 31, 2010, 2009 and 2008, there were no significant modifications affecting any of our share-based payment arrangements.

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

Cash received from stock options exercised and actual tax benefit realized for the tax deductions from stock options exercised during the years ended December 31, 2010, 2009 and 2008 were as follows:

Share-based Compensation Plans	Years Ended December 31, 2010	2009	2008
	(in thousands)		
Cash Received from Stock Options Exercised	$ 14,134	$ 567	$ 2,170
Actual Tax Benefit Realized for the Tax Deductions from Stock Options Exercised	706	35	219

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

16. PROPERTY, PLANT AND EQUIPMENT

Depreciation, Depletion and Amortization

We provide for depreciation of Property, Plant and Equipment, excluding coal-mining properties, on a straight-line basis over the estimated useful lives of property, generally using composite rates by functional class as follows:

2010	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depre Life R
	(in millions)			(in years)	(in millions)			(in ye
Generation	$ 14,147	$ 6,537	1.6 - 3.8 %	9 - 132	$ 10,205	$ 3,788	2.2 - 5.1 %	20 -
Transmission	8,576	2,481	1.4 - 3.0 %	25 - 87	-	-	- - - %	- -
Distribution	14,208	3,607	2.4 - 3.9 %	11 - 75	-	-	- - - %	- -
CWIP	2,615 (a)	47	N.M.	N.M.	143	9	N.M.	N.M
Other	2,685	1,268	3.0 - 12.5 %	5 - 55	1,161	329	N.M.	N.M
Total	$ 42,231	$ 13,940			$ 11,509	$ 4,126		

2009	Regulated				Nonregulated			
Functional Class of Property	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges	Property, Plant and Equipment	Accumulated Depreciation	Annual Composite Depreciation Rate Ranges	Depre Life R
	(in millions)			(in years)	(in millions)			(in ye
Generation	$ 13,047	$ 6,460	1.6 - 3.8 %	9 - 132	$ 9,998	$ 3,479	1.9 - 3.3 %	20 -
Transmission	8,315	2,478	1.4 - 2.7 %	25 - 87	-	-	- - - %	- -
Distribution	13,549	3,421	2.4 - 3.9 %	11 - 75	-	-	- - - %	- -
CWIP	2,866 (a)	(19)	N.M.	N.M.	165	6	N.M.	N.M
Other	2,616	1,130	4.2 - 12.8 %	5 - 55	1,128	385	N.M.	N.M
Total	$ 40,393	$ 13,470			$ 11,291	$ 3,870		

2008	Regulated		Nonregulated	
Functional Class of Property	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges (in years)	Annual Composite Depreciation Rate Ranges	Depreciable Life Ranges (in years)
Generation	1.6 - 3.5 %	9 - 132	2.6 - 5.1 %	20 - 61
Transmission	1.4 - 2.7 %	25 - 87	- - - %	- - -
Distribution	2.4 - 3.9 %	11 - 75	- - - %	- - -
CWIP	N.M.	N.M.	N.M.	N.M.
Other	4.9 - 11.3 %	5 - 55	N.M.	N.M.

(a) Includes CWIP related to SWEPCo's Arkansas jurisdictional share of the Turk Plant.

N.M. Not Meaningful

We provide for depreciation, depletion and amortization of coal-mining assets over each asset's estimated useful life or the estimated life of each mine, whichever is shorter, using the straight-line method for mining structures and equipment. We use either the straight-line method or the units-of-production method to amortize mine development costs and deplete coal rights based on estimated recoverable tonnages. We include these costs in the cost of coal charged to fuel expense.

For rate-regulated operations, the composite depreciation rate generally includes a component for non-asset retirement obligation (non-ARO) removal costs, which is credited to Accumulated Depreciation and Amortization. Actual removal costs incurred are charged to Accumulated Depreciation and Amortization. Any excess of accrued non-ARO removal costs over actual removal costs incurred is reclassified from Accumulated Depreciation and Amortization and reflected as a regulatory liability. For nonregulated operations, non-ARO removal costs are expensed as incurred.

As of January 1, 2010, DHLC was deconsolidated and is now reported as an equity investment on our Consolidated Balance Sheet. Also, see the "ASU 2009-17 'Consolidations' " section of Note 2 for a discussion of the impact of new accounting guidance effective January 1, 2010.

Asset Retirement Obligations (ARO)

We record ARO in accordance with the accounting guidance for "Asset Retirement and Environmental Obligations" for our legal obligations for asbestos removal and for the retirement of certain ash disposal facilities, closure and monitoring of underground carbon storage facilities at Mountaineer Plant, wind farms and certain coal mining facilities, as well as for nuclear decommissioning of our Cook Plant. We have identified, but not recognized, ARO liabilities related to electric transmission and distribution assets as a result of certain easements on property on which we have assets. Generally, such easements are perpetual and require only the retirement and removal of our assets upon the cessation of the property's use. We do not estimate the retirement for such easements because we plan to use our facilities indefinitely. The retirement obligation would only be recognized if and when we abandon or cease the use of specific easements, which is not expected.

The following is a reconciliation of the 2010 and 2009 aggregate carrying amounts of ARO:

	Carrying Amount of ARO
	(in millions)
ARO at December 31, 2008	$ 1,158
Accretion Expense	73
Liabilities Incurred	47
Liabilities Settled	(24)
Revisions in Cash Flow Estimates	5
ARO at December 31, 2009 (a)	1,259
DHLC Deconsolidation (c)	(12)
Accretion Expense	75
Liabilities Incurred	32
Liabilities Settled	(20)
Revisions in Cash Flow Estimates	64
ARO at December 31, 2010 (b)	$ 1,398

(a) The current portion of our ARO, totaling $5 million, is included in Other Current Liabilities on our 2009 Consolidated Balance Sheet.
(b) The current portion of our ARO, totaling $4 million, is included in Other Current Liabilities on our 2010 Consolidated Balance Sheet.
(c) We adopted ASU 2009-17 effective January 1, 2010 and deconsolidated DHLC. As a result, we record only 50% of the final reclamation based on our share of the obligation instead of the previous 100%.

As of December 31, 2010 and 2009, our ARO liability was $1.4 billion and $1.3 billion, respectively, and included $930 million and $878 million, respectively, for nuclear decommissioning of the Cook Plant. As of December 31, 2010 and 2009, the fair value of assets that are legally restricted for purposes of settling the nuclear decommissioning liabilities totaled $1.2 billion and $1.1 billion, respectively, and are recorded in Spent Nuclear Fuel and Decommissioning Trusts on our Consolidated Balance Sheets.

Allowance for Funds Used During Construction (AFUDC) and Interest Capitalization

Our amounts of allowance for borrowed, including interest capitalized, and equity funds used during construction is summarized in the following table:

	Years Ended December 31,		
	2010	2009	2008
	(in millions)		
Allowance for Equity Funds Used During Construction	$ 77	$ 82	$ 45
Allowance for Borrowed Funds Used During Construction	53	67	75

Jointly-owned Electric Facilities

We have electric facilities that are jointly-owned with nonaffiliated companies. Using our own financing, we are obligated to pay a share of the costs of these jointly-owned facilities in the same proportion as our ownership interest. Our proportionate share of the operating costs associated with such facilities is included in our Consolidated Statements of Income and the investments and accumulated depreciation are reflected in our Consolidated Balance Sheets under Property, Plant and Equipment as follows:

			Company's Share at December 31, 2010		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	301	8	49
J.M. Stuart Generating Station (c)	Coal	26.0 %	507	23	163
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	771	10	366
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	258	5	192
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0 %	116	7	62
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9 %	503	10	358
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3 %	395	4	201
Turk Generating Plant (h)	Coal	73.33 %	-	971	-
Transmission	N/A	(d)	63	3	48

			Company's Share at December 31, 2009		
	Fuel Type	Percent of Ownership	Utility Plant in Service	Construction Work in Progress	Accumulated Depreciation
				(in millions)	
W.C. Beckjord Generating Station (Unit No. 6) (a)	Coal	12.5 %	$ 19	$ -	$ 8
Conesville Generating Station (Unit No. 4) (b)	Coal	43.5 %	301	4	45
J.M. Stuart Generating Station (c)	Coal	26.0 %	499	15	153
Wm. H. Zimmer Generating Station (a)	Coal	25.4 %	767	4	355
Dolet Hills Generating Station (Unit No. 1) (f)	Lignite	40.2 %	255	4	188
Flint Creek Generating Station (Unit No. 1) (g)	Coal	50.0 %	116	5	61
Pirkey Generating Station (Unit No. 1) (g)	Lignite	85.9 %	497	8	350
Oklaunion Generating Station (Unit No. 1) (e)	Coal	70.3 %	390	6	195
Turk Generating Plant (h)	Coal	73.33 %	-	688	-
Transmission	N/A	(d)	70	1	47

(a) Operated by Duke Energy Corporation, a nonaffiliated company.
(b) Operated by CSPCo.
(c) Operated by The Dayton Power & Light Company, a nonaffiliated company.
(d) Varying percentages of ownership.
(e) Operated by PSO and also jointly-owned (54.7%) by TNC.
(f) Operated by CLECO, a nonaffiliated company.
(g) Operated by SWEPCo.

(h) Turk Generating Plant is currently under construction with a projected commercial operation date of 2012. SWEPCo jointly owns the plant with Arkansas Electric Cooperative Corporation (11.67%), East Texas Electric Cooperative (8.33%) and Oklahoma Municipal Power Authority (6.67%). Through December 2010, construction costs totaling $279 million have been billed to the other owners.

N/A Not Applicable

17. COST REDUCTION INITIATIVES

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

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

	Total (in millions)
Incurred	$ 293
Settled	283
Adjustments	7
Remaining Balance at December 31, 2010	$ 17

These costs relate primarily to severance benefits. They are included primarily in Other Operation on the Consolidated Statements of Income and Other Current Liabilities on the Consolidated Balance Sheets. Approximately 99% of the expense was within the Utility Operations segment.

18. UNAUDITED QUARTERLY FINANCIAL INFORMATION

In our opinion, the unaudited quarterly information reflects all normal and recurring accruals and adjustments necessary for a fair presentation of our net income for interim periods. Quarterly results are not necessarily indicative of a full year's operations because of various factors. Our unaudited quarterly financial information is as follows:

	2010 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,569	$ 3,360	$ 4,064	$ 3,434
Operating Income	758	394 (a)	1,025	486 (b)
Net Income	346	137 (a)	557	178 (b)
Amounts Attributable to AEP Common Shareholders:				
Net Income	344	136 (a)	555	176 (b)
Basic Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (c)	0.72	0.28	1.16	0.37
Diluted Earnings per Share Attributable to AEP Common Shareholders:				
Earnings per Share (c)	0.72	0.28	1.16	0.37

	2009 Quarterly Periods Ended			
	March 31	June 30	September 30	December 31
	(in millions - except per share amounts)			
Total Revenues	$ 3,458	$ 3,202	$ 3,547	$ 3,282
Operating Income	750	682	858	481
Income Before Extraordinary Loss	363	322	446	239
Extraordinary Loss, Net of Tax	-	(5)(d)	-	-
Net Income	363	317	446	239
Amounts Attributable to AEP Common Shareholders:				
Income Before Extraordinary Loss	360	321	443	238
Extraordinary Loss, Net of Tax	-	(5)(d)	-	-
Net Income	360	316	443	238
Basic Earnings (Loss) per Share Attributable to AEP Common Shareholders:				
Earnings per Share Before Extraordinary Loss (c)	0.89	0.68	0.93	0.49
Extraordinary Loss per Share	-	(0.01)	-	-
Earnings per Share (c)	0.89	0.67	0.93	0.49

Diluted Earnings (Loss) per Share Attributable to AEP				
Common Shareholders:				
Earnings per Share Before Extraordinary Loss (c)	0.89	0.68	0.93	0.49
Extraordinary Loss per Share	-	(0.01)	-	-
Earnings per Share (c)	0.89	0.67	0.93	0.49

(a) See Note 17 for discussion of expenses related to cost reduction initiatives recorded in the second quarter of 2010.

(b) Includes a $43 million refund provision for the 2009 Significantly Excessive Earnings Test in addition to various other provisions for certain regulatory and legal matters.

(c) Quarterly Earnings Per Share amounts are meant to be stand-alone calculations and are not always additive to full-year amount due to rounding.

(d) See “SWEPCo Texas Restructuring” in “Extraordinary Item” section of Note 2 for discussion of the extraordinary loss recorded in the second quarter of 2009.

CORPORATE AND SHAREHOLDER INFORMATION

Corporate Headquarters
1 Riverside Plaza
Columbus, OH 43215-2373
614-716-1000
AEP is incorporated in the State of New York.

Stock Exchange Listing – The Company's common stock is traded principally on the New York Stock Exchange under the ticker symbol AEP.

Internet Home Page – Information about AEP, including financial documents, Securities and Exchange Commission (SEC) filings, news releases, investor presentations, shareholder information and customer service information, is available on the Company's home page on the Internet at www.AEP.com/investors.

Inquiries Regarding Your Stock Holdings – Registered shareholders (shares that you own, in your name) should contact the Company's transfer agent, listed below, if you have questions about your account, address changes, stock transfer, lost certificates, direct deposits, dividend checks and other administrative matters. You should have your Social Security number or account number ready; the transfer agent will not speak to third parties about an account without the shareholder's approval or appropriate documents.

Transfer Agent & Registrar
Computershare Trust Company, N.A.
P.O. Box 43078
Providence, RI 02940-3078
For overnight deliveries:
Computershare Trust Company, N.A.
250 Royall Street
Canton, MA 02021-1011
Telephone Response Group:1-800-328-6955
Internet address: www.computershare.com/investor
Hearing Impaired #: TDD: 1-800-952-9245

Beneficial Holders – (Stock held in a bank or brokerage account) – When you purchase stock and it is held for you by your broker, it is listed with the Company in the broker's name, and this is sometimes referred to as "street name" or a "beneficial owner." AEP does not know the identity of individual shareholders who hold their shares in this manner; we simply know that a broker holds a certain number of shares which may be for any number of customers. If you hold your stock in street name, you receive all dividend payments, annual reports and proxy materials through your broker. Therefore, questions about your account should be directed to your broker.

Dividend Reinvestment and Direct Stock Purchase Plan – A Dividend Reinvestment and Direct Stock Purchase Plan is available to all investors. It is an economical and convenient method of purchasing shares of AEP common stock, through initial cash investments, cash dividends and/or additional optional cash purchases. You may obtain the Plan prospectus and enrollment authorization form by contacting the transfer agent or by visiting www.AEP.com/investors/directstockpurchase.

Financial Community Inquiries – Institutional investors or securities analysts who have questions about the Company should direct inquiries to Bette Jo Rozsa, 614-716-2840, bjrozsa@AEP.com; Julie Sherwood, 614-716-2663, jasherwood@AEP.com; or Sara Macioch, 614-716-2835, semacioch@AEP.com. Individual shareholders should contact Kathleen Kozero, 614-716-2819, klkozero@AEP.com.

Number of Shareholders – As of December 31, 2010, there were approximately 91,000 registered shareholders and approximately 331,000 shareholders holding stock in street name through a bank or broker. There were 480,807,156 shares outstanding at December 31, 2010.

Form 10-K – Upon request, we will provide without charge a copy of our Form 10-K for the fiscal year ended December 31, 2010. A copy can be obtained via mail with a written request to AEP Investor Relations, by telephone at 1-800-237-2667 or electronically at klkozero@AEP.com.

Executive Leadership Team

Name	Age	Office
Michael G. Morris	64	Chairman of the Board and Chief Executive Officer
Nicholas K. Akins	50	President
Carl L. English	64	Vice Chairman
D. Michael Miller	63	Senior Vice President, General Counsel and Secretary
Robert P. Powers	56	President – AEP Utilities
Brian X. Tierney	43	Executive Vice President and Chief Financial Officer
Susan Tomasky	57	President – AEP Transmission